YUKON RIVER BASIN STUDY

PROJECT REPORT: ENERGY NO. 2

ELECTRIC TRANSMISSION INTERCONNECTION STUDY

SYSTEM ENGINEERING DIVISION

B.C. HYDRO

This project was completed for the Yukon River Basin Study, an intergovernmental study funded by the governments of Canada, Yukon and British Columbia.

May 1983

VANCOUVER, BRITISH COLUMBIA

YUKON RIVER BASIN STUDY

PROJECT REPORT: ENERGY NO. 2

ELECTRIC TRANSMISSION INTERCONNECTION STUDY

SYSTEM ENGINEERING DIVISION

B.C. HYDRO

May 1983

VANCOUVER, BRITISH COLUMBIA

YUKON RIVER BASIN STUDY

PROJECT REPORT: ENERGY NO. 2

ELECTRIC TRANSMISSION INTERCONNECTION STUDY

SYSTEM ENGINEERING DIVISION

May 1983

B.C. HYDRO

VANCOUVER, BRITISH COLUMBIA

This report was funded by the Yukon River Basin Committee under the terms of "An Agreement Respecting Studies and Planning of Water Resources in the Yukon River Basin" between Canada, British Columbia and Yukon. The views, conclusions and recommendations are those of the author and not necessarily those of the (Energy Work Group) Yukon River Basin Committee, the Government of Canada or the Government of Yukon. This report is a background paper for use as input to the Program Report of the Energy Work Group. Please refer to the Final Report of the Yukon River Basin Committee for the views of this committee.

ELECTRIC TRANSMISSION INTERCONNECTION STUDY

CONTENTS

Section	Subject	Page
1.0	INTRODUCTION	1 - 1
2.0	PURPOSE AND CONCLUSIONS	
	2.1 Purpose	2 - 1
	2.2 Conclusions	2 - 1
3.0	TRANSMISSION INTERCONNECTIONS	
	3.1 General Characteristics of Interconnections	3 - 1
	3.2 Technical Feasibility of Proposed Interconnections	3 - 3
4.0	GENERATION RESOURCES IN NORTHERN BRITISH COLUMBIA	
	4.1 Stikine-Iskut and Liard	4 - 1
	4.2 Yukon-Taku	4 - 1
5.0	TRANSMISSION LINE ROUTE LOCATION	
	5.1 British Columbia - Yukon Routes	5 - 1
	5.2 Alaska and Northwest Territories - Yukon Routes	5 - 2
6.0	INTERCONNECTION ALTERNATIVES AND STUDY CRITERIA	6 - 1
7.0	TRANSMISSION LINE PLANNING PROCESS FOR REGULATED PROJECTS	7 - 1
8.0	COST ESTIMATES	
	8.1 Costing Procedure	8 - 1
	8.2 Cost of Alternatives	8 - 3

CONTENTS - (Cont'd)

TABLES

Table No.	
8-1	Derivation of Annual Cost Charges for a Transmission Project
8-2	Annual Cost Summary of B.C. Interconnection Alternatives
8-3	Average Delivery Cost of Transmission for B.C. Interconnections
8-4	Direct Transmission Costs of B.C., Alaska and NWT Interconnection Alternatives

FIGURES

Figure No.	
3-1	Transmission Line Capacities for Long Distance
4-1	Location Map for Potential Projects
5-1	Route Study Plan - Stikine Collector to Whitehorse and Stikine Collector to Faro
5-2	Route Study Plan - Liard (Devils Gorge) to Faro
5-3	Construction Schedule for B.C. Interconnection Alternatives
5-4	Location Map - Great Bear River Generating Site and Transmission Line Route to Ross River
5-5	Location Map - Susitna River Generating Site and Transmission Line Route to Whitehorse
8-1	Average Delivery Cost of Transmission for B.C. Interconnection Alternatives at 4 percent Discount Rate
8-2	Average Delivery Cost of Transmission for B.C. Interconnection Alternatives at 8 percent Discount Rate

CONTENTS - (Cont'd)

APPENDICES

Appendix No.	
A	Terms of Reference and Ammendments
B	Power Flow and Cost Studies
C	Guide to Energy Project Review Process
D	Demand Scenarios for B.C. Hydro

SECTION 1.0 - INTRODUCTION

In 1980, the governments of Canada, British Columbia and the Yukon agreed to support and participate in a Yukon River Basin Study. A Yukon River Basin Committee was formed and eight work groups, including an Energy Work Group, were established.

The Energy Work Group was assigned the complementary tasks of evaluating the energy resources of the Yukon River Basin, and of investigating the potential for interconnection with electric power generation developments outside the Yukon.

B.C. Hydro, as a represented member of the Energy Work Group, conducted a brief study in March 1982 of a single 500 kV transmission line between Whitehorse and a proposed hydroelectric power project on the Stikine River in British Columbia. Their conclusion was that the proposed interconnection was technically feasible. On the basis of this favorable result the Work Group then commissioned B.C. Hydro to conduct a further Electric Transmission Interconnection Study, the requirements of which are contained in the document "Yukon River Basin Study, Electric Transmission Interconnection Study - Terms of Reference". A copy of the original Terms of Reference is attached in Appendix A together with a list of ammendments agreed upon in subsequent Energy Work Group meetings.

SECTION 2.0 - PURPOSE AND CONCLUSIONS

2.1 PURPOSE

The purpose of the study was to investigate the engineering and economic feasibility of alternative electric interconnections between Yukon regional load centres and generation sources outside the Yukon.

Five alternative interconnections between the Yukon and sources outside the Yukon were evaluated.

1. Stikine - Whitehorse)
2. Stikine - Faro) (British Columbia alternatives)
3. Liard - Faro)
4. Bennett Field - Ross River (Northwest Territories alternative)
5. Susitna River - Whitehorse (Alaska alternative)

2.2 CONCLUSIONS

1. A transmission voltage of 500 kV is feasible for each of the interconnection alternatives. The relatively low transmission line loading does not justify consideration of a voltage higher than 500 kV and the long transmission distances require a voltage greater than 230 kV.

2. For each of the five alternatives, one 500 kV transmission line would meet all capacity and voltage requirements, but would not provide a firm supply.

3. The Stikine and Liard projects are the only feasible generating sites in B.C. for possible interconnection with the Yukon.

(No survey was done of alternative generation sites in Alaska or the Northwest Territories. The Susitna River and Bennett Field sites were chosen only as representative examples for purposes of this transmission study.)

4. The B.C. - Yukon alternatives are technically sound as demonstrated in power flow simulation studies.

5. Less information was available for the Alaska and Northwest Territories alternatives. However, preliminary power flow studies indicate that while 500 kV interconnections appear feasible, they would impose large economic penalties due to greater transmission distances and construction costs, plus higher energy costs than the British Columbia alternatives.

6. An intermediate switching station would be required at the approximate midpoint of each interconnection to reduce switching overvoltages. Due to the greater route length, the Alaska interconnection would require two such stations. Alternative methods of controlling overvoltages are possible but would require extensive studies.

7. The Stikine Collector to Whitehorse alternative would require the least transmission line construction: 465 km of transmission line compared to 575 km for Stikine Collector - Faro alternative, 585 km for Liard (Devils Gorge) - Faro, 680 km for NWT (Bennett Field) - Ross River, and 980 km for Alaska (Susitna River) - Whitehorse. Dependent on the alternative, load centres are assumed at Whitehorse, Faro or Ross River and local subtransmission within the Yukon electric system is not considered.

8. The Stikine Collector - Whitehorse alternative would require the least direct capital cost and total annual charges for each of the three Yukon load levels studied. The relative costs of the

alternatives are dependent on the route lengths selected and would vary if the routes were changed.

9. The total uniform annual costs of the B.C. interconnection alternatives (1982 prices, including capital, losses, and annual operating charges) are:

	Annual Cost ($M)		
Yukon Load	150 MW	300 MW	475 MW
Stikine Collector - Whitehorse	18.9	19.4	20.2
Liard (Devils Gorge) - Faro	22.4	23.2	24.3
Stikine Collector - Faro	23.3	24.2	25.2

Total capital costs for all alternatives are given in Table 8-4.

10. A ranking of the three B.C. alternatives in terms of average delivery cost per kilowatt-hour indicates that, for over the range of projected Yukon loads studied, the Stikine Collector - Whitehorse alternative would have the lowest cost followed by the Liard (Devils Gorge) - Faro scheme. Reference Fig. 8-1.

11. The effect of increasing the discount rate to 8 percent does not change this ranking but does increase the average delivery cost. Reference Fig. 8-2.

SECTION 3.0 - TRANSMISSION INTERCONNECTIONS

3.1 GENERAL CHARACTERISTICS OF INTERCONNECTIONS

The main purpose of interconnections between electric utilities are to exchange energy and to permit sharing of generation reserves. The objective in both cases is to reduce costs and to increase opportunities for purchase and sale of energy and capacity.

There are many benefits to interconnections. All utilities must provide adequate generation reserves to ensure that load can be served when units are out of service. An interconnection can provide a portion of this reserve. If there is diversity in each utility's generation downtimes, energy can be taken from a neighbour during these periods and again less reserve is necessary in each region. During forced outages of generation an interconnection will provide immediate back-up supply. If there is load diversity (hourly, daily, seasonal) or generation diversity (hydro, fossil, diesel) between two regions, more economic dispatch of generation can be arranged if an interconnection exists. System voltages remain more constant, system operation is more flexible and, if the interconnection is properly designed and operated, reliability of service is improved.

Interconnections have important characteristics which must be considered at the planning stage. These include regulatory and contractual aspects as well as technical considerations. From the system planning viewpoint there is no distinction between a transmission line connecting two utilities and one utility's transmission line whose primary function is, say, the interconnection of remote generation with a load centre. It is true that interconnections are administered differently, dispatched differently, and controlled differently, but when a major disturbance occurs such distinctions disappear. The entire interconnected network

responds. It is therefore important to plan interconnections as part of a larger whole; their performance can only be fully assessed by looking at operating conditions and disturbances throughout the interconnected system, not just those conditions and disturbances directly involving the interconnection.

Interconnection characteristics depend to a large extent on the sizes of the two connected utilities and the capacity of the tie relative to those sizes. For example, if an interconnection has a relatively low capacity so that it is often fully loaded during normal energy exchanges, then it will be unable to provide much emergency transfer capability. If the tie is to contribute to generation reserves its remaining pick-up capacity is the important parameter, not the total capacity. Another example is a relatively weak tie used primarily to import energy. If this tie is subject to overload and tripping whenever the largest generator in the importing region trips, the net deficiency in that region is the generator plus the import. In a case like this the tie results in even greater generation reserves being required.

Utilities planning an interconnection have an obligation to each other to provide a tie strong enough to carry all scheduled energy and capacity exchanges and also to withstand all likely disturbances. In addition, utilities must recognize that once an interconnection is established it is possible to export or import trouble as well as energy. Each utility must be prepared to aid its neighbour but must also design its own system in such a way that the impacts of internal disturbances are not felt by the neighbour beyond the extent planned for and agreed to. System Planning guidelines are essential to ensure the reliable design and operation of the interconnection. The primary emphasis of such guidelines is on the avoidance of interruptions in one region causing further interruptions (cascading) in adjoining regions. Most planners agree that if an interconnection is properly designed and if comprehensive agreements and guidelines are established the

interruptions of service prevented by the interconnection will far exceed the number of interruptions caused by the interconnection.

3.2 TECHNICAL FEASIBILITY OF PROPOSED INTERCONNECTIONS

A transmission system is defined when its terminal locations and its power transfer capability are specified. If the specified transfer capability is less than a few thousand megawatts, and if a route with acceptable terrain and climate exists between the specified terminal locations, then the technical feasibility of the proposed transmission system is practically assured. The cost of the system will be influenced to a degree by terrain and climate but will be primarily determined by the transmission distance and the specified capacity.

For this study, transmission routes were selected by an in-office survey of topographic and climatological mapping of the region. On-site investigation was unnecessary since the objective was not to design a line but more simply to establish that feasible routes exist.

As transmission distance increases, transmission losses also increase and it becomes more difficult to maintain constant voltage under varying load conditions. At the same time, the electromechanical stability of the system (the ability of all the generators in the system to remain in synchronism) decreases. A higher design voltage improves all of these factors and this leads to higher transmission line capacity as can be seen in Fig. 3-1 where capacity is plotted as a function of distance for a number of standard voltages. In the B.C. Hydro system the standard voltages now employed for major transmission lines are 230 kV and 500 kV. In this study, the highest loading considered is 475 MW which is relatively light for 500 kV transmission but the distances are so great that 500 kV is still the preferred design voltage. Some reduction in transmission design voltage might be possible if detailed design were to proceed but is beyond the scope of this study. Such reduction in

design voltage is not expected to result in significant reduction in unit costs for energy delivery.

With line loading of 475 MW, or less, the conductor size would be governed by audible noise and radio interference limitations, not by losses. For this reason, the smallest conductor now employed in the B.C. Hydro 500 kV system was assumed in all cases.

All of the computer simulation studies assumed 500 kV transmission as just described. The purpose of the studies was to calculate losses and voltage levels during various loading conditions and from these results specify substation requirements for each alternative so that economic comparisons would be between feasible systems. In the process, the technical feasibility of each 500 kV alternative, previously established on general transmission planning principles, was confirmed.

TRANSMISSION LINE CAPACITIES FOR LONG DISTANCES

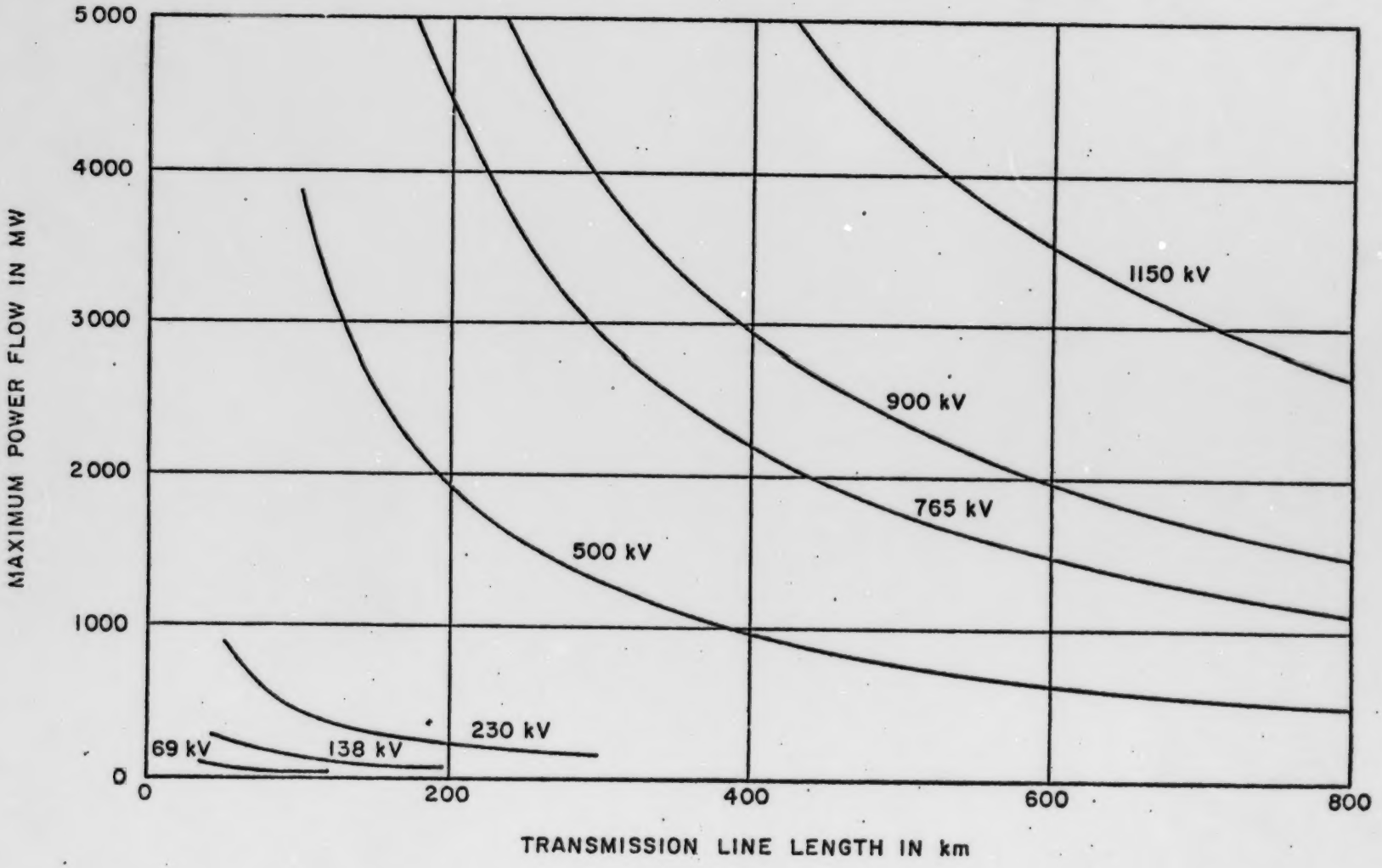


FIGURE 3-1

SECTION 4.0 - GENERATION RESOURCES IN NORTHERN BRITISH COLUMBIA

4.1 STIKINE-ISKUT AND LIARD

B.C. Hydro in now investigating the possibilities of developing the hydroelectric generating potential of the Stikine-Iskut river system and of the Liard River. These rivers, and the potential damsites, are located in the northwestern and northern areas of British Columbia respectively, as shown in Fig. 4-1.

Preliminary study results indicate that a 500 kV ac transmission scheme would be the most economic and technically sound plan in each case to transmit power from the hydroelectric sites to the existing B.C. Hydro 500 kV system.

The Stikine and Liard projects are the only feasible generating sites in B.C. for possible interconnection with the Yukon. This is discussed further in Section 4.2.

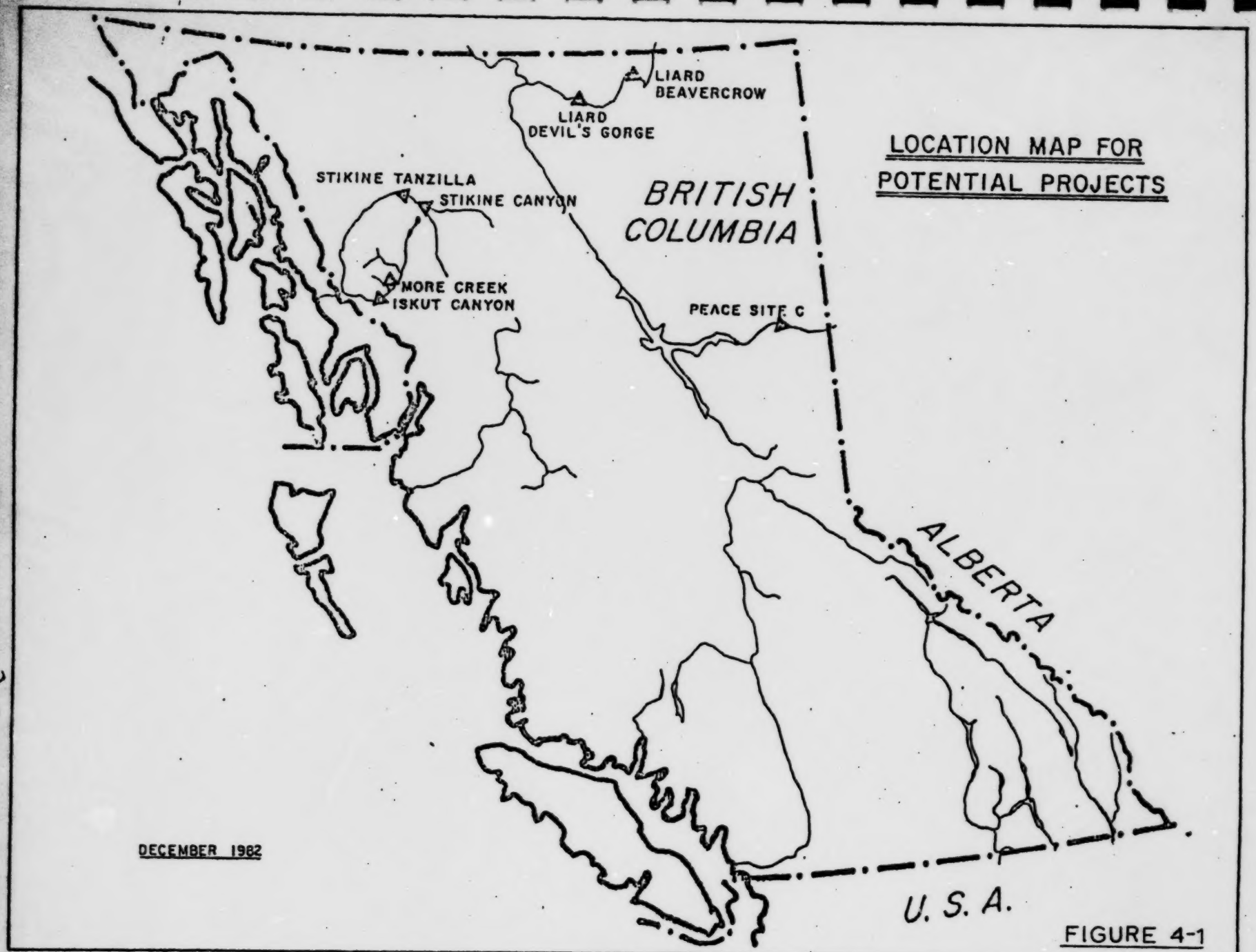
4.2 YUKON-TAKU

None of the hydroelectric potential of the Yukon-Taku basin in B.C. has been developed. A Yukon-Taku generation development study was presented in a 1972 B.C. Energy Board report. In 1974, B.C. Hydro authorized Teshmont Consultants, Winnipeg, to carry out a feasibility study of transmitting power from potential hydro sites on the Yukon River in northern B.C. to the Lower Mainland area of the province. No further studies have been initiated by B.C. Hydro since those dates.

As B.C. Hydro has selected the Stikine-Iskut and the Liard river basins to be the long-term power supply sources for British Columbia,

development of the Yukon - Taku power potential appears improbable in the forseeable future. Therefore, for the purpose of this report, it has been assumed that there will be no major hydroelectric developments in British Columbia involving the Yukon and Taku rivers during the period of interest.

B.C. Hydro has recently carried out an inventory of other hydroelectric power sites in the B.C. portion of the Yukon River Basin. None of the 14 sites identified appear to warrant more detailed studies because of their small power potential in relation to long transmission distances.



LOCATION MAP FOR
POTENTIAL PROJECTS

DECEMBER 1982

FIGURE 4-1

SECTION 5.0 - TRANSMISSION LINE ROUTE LOCATION

5.1 BRITISH COLUMBIA - YUKON ROUTES

As agreed in the Terms of Reference, the Transmission Interconnection Study limits transmission line route location to an office study of contour maps and other published information relating to the proposed generation sources in northern B.C. This office study was conducted by B.C. Hydro's Transmission Projects Division. The following material is attached:

1. Preliminary route study plan, Stikine Collector to Whitehorse and Stikine Collector to Faro, Fig. 5-1.

2. Preliminary route study plan, Liard (Devils Gorge) to Faro, Fig. 5-2.

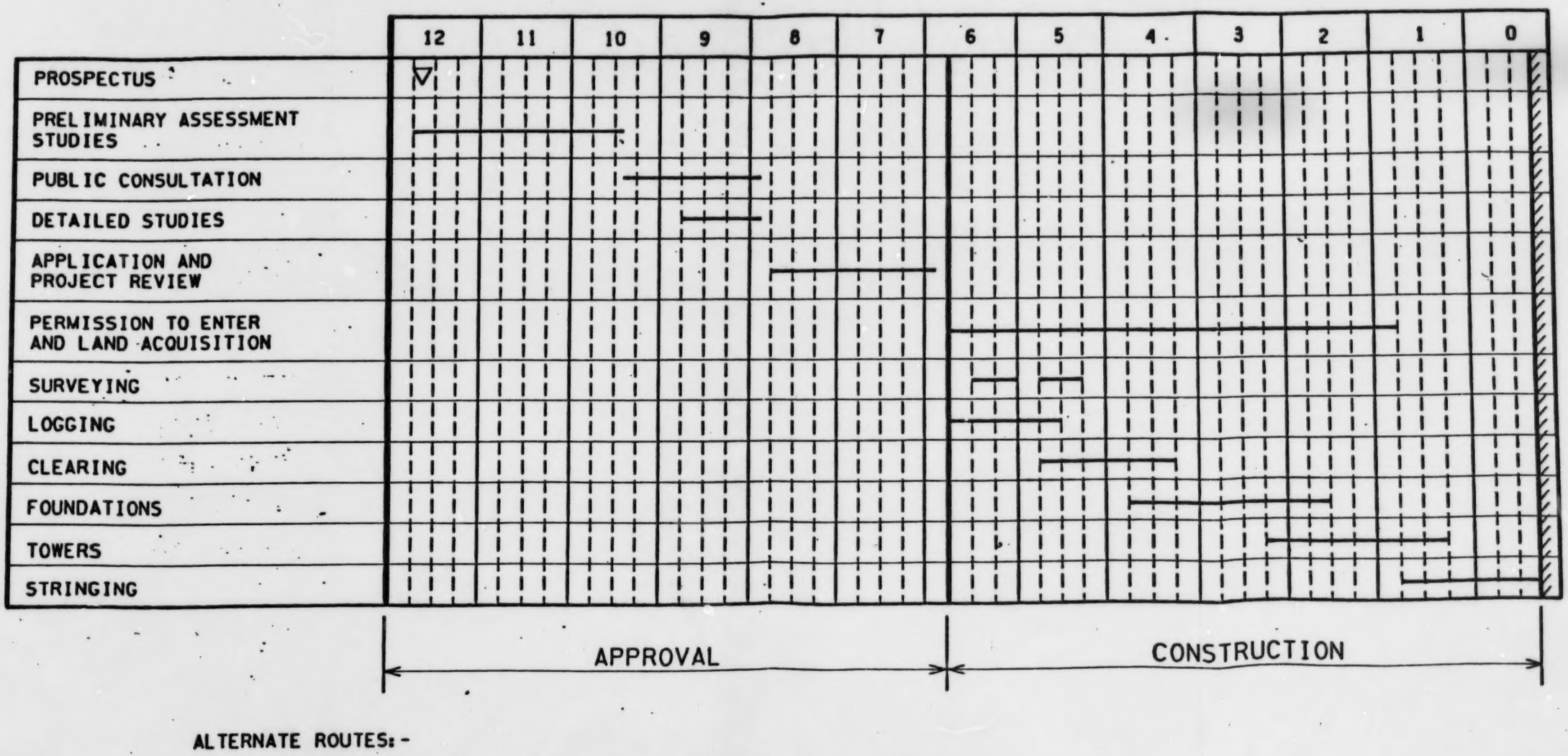
3. Preliminary construction schedule, Fig. 5-3.

No environmental impact studies of the proposed routes were carried out although sensitive areas such as Native Indian reservations and Provincial and Territorial parks were avoided. Within B.C., such studies would require evaluation of the potential environmental impact of transmission line construction along the technically feasible corridors. This would include an assessment of the impact on agriculture, forestry, vegetation, terrain, fisheries, wildlife, recreation, visual resources, heritage resources, regional resource development, social and economic impacts, and land use.

5.2 ALASKA AND NORTHWEST TERRITORIES - YUKON ROUTES

At the Energy Work Group meeting of 4 November 1982, locations of potential hydroelectric sources in Alaska and the Northwest Territories (NWT) were discussed. The Great Bear River sites in NWT (Bennett Field) with a possible transmission line down the Canol Road, was suggested as was the Susitna River site in Alaska, north of Anchorage. Basically, the routes proposed reflect the shortest distance to the nearest tie-in point of the Yukon system, generally following existing highway alignments. The transmission line routes for the NWT and Alaska interconnection alternatives are shown in Figs. 5-4 and 5-5 respectively.

YUKON INTERCONNECTION - 500 kV TRANSMISSION LINE - PRELIMINARY SCHEDULE



ALTERNATE ROUTES:-

STIKINE COLLECTOR TO WHITEHORSE - 465 km

LIARD (DEVILS GORGE) TO FARO - 585 km

STIKINE COLLECTOR TO FARO - 575 km

FIGURE 5-3

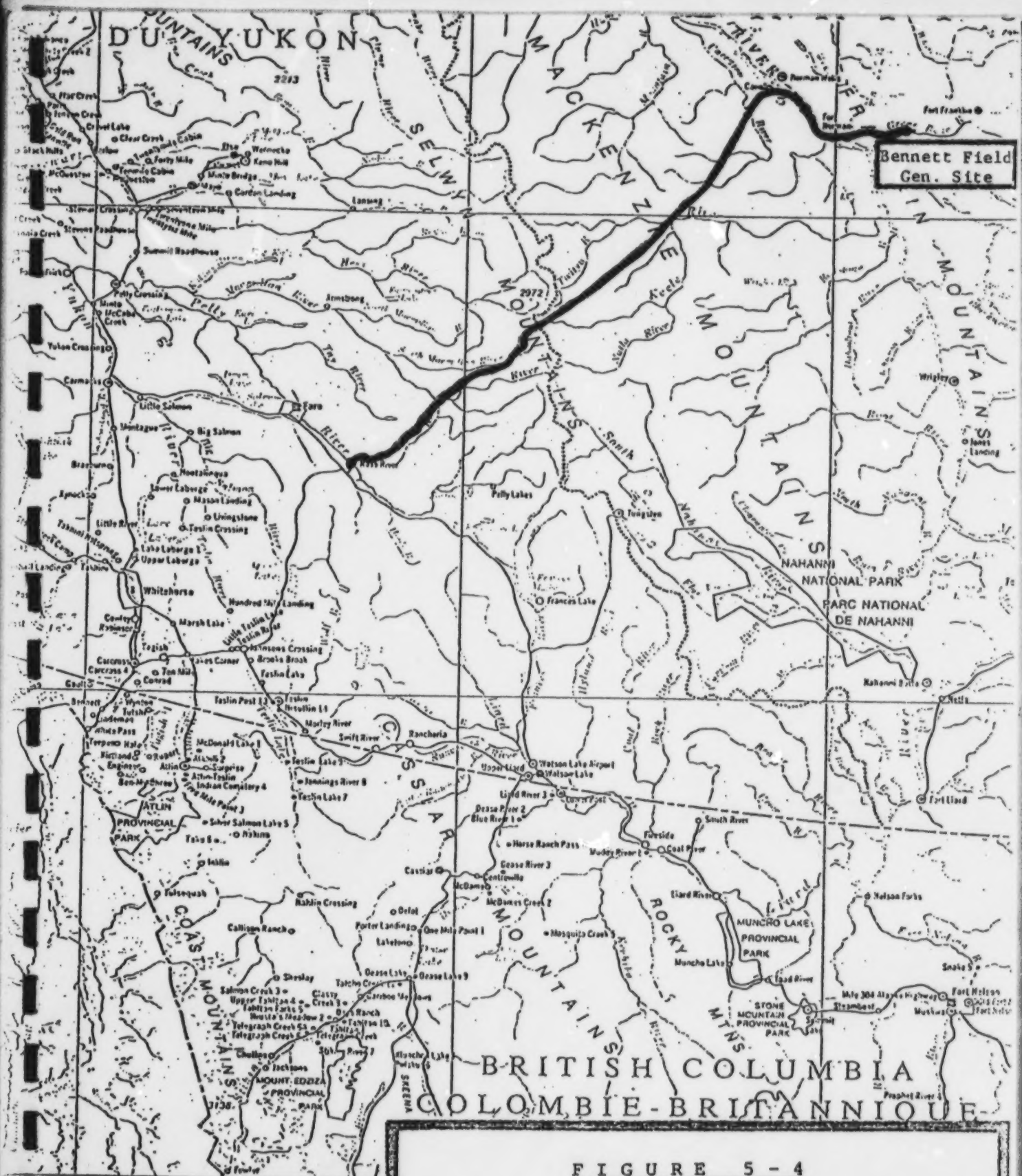
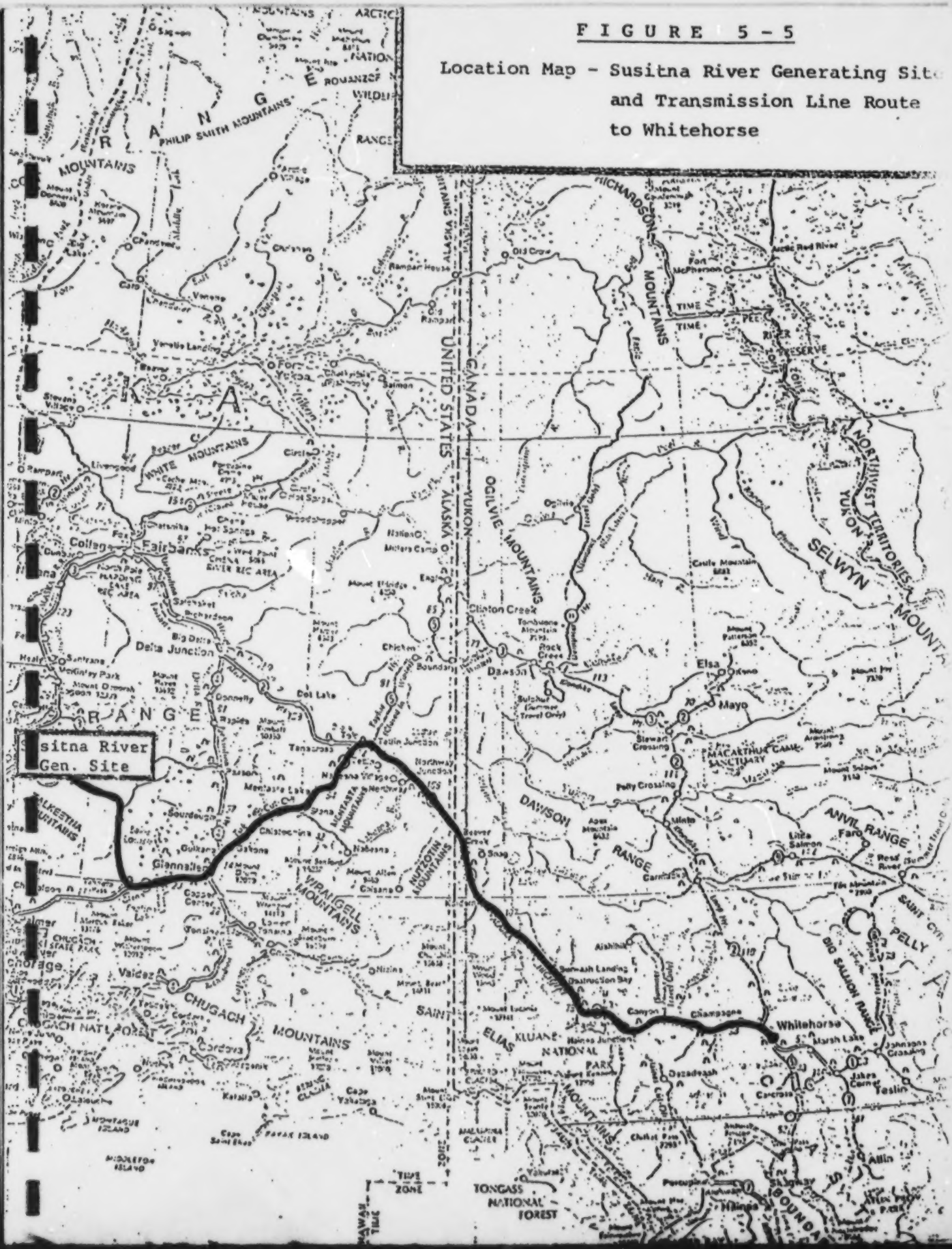


FIGURE 5 - 4

Location Map - Great Bear River Generating Site (Bennett Field) and Transmission Line Route to Ross River

FIGURE 5-5

Location Map - Susitna River Generating Site and Transmission Line Route to Whitehorse


Susitna River Gen. Site
Whitehorse
Fairbanks
Delta Junction
Glennallen
Valdez
Anchorage
Dawson
Mayo
Elsa
Faro
Watson Lake
Carmacks
Haines Junction
Destruction Bay
Burwash Landing
Tok
Tetlin Junction
Northway Junction
Tanacross
Big Delta
Eagle
Circle
Fort Yukon
Rampart
Stevens Village
Minto
Nenana
Healy
Cantwell
Paxson
Gulkana
Copper Center
Chitina
Cordova
Tonsina
Nizina
Slana
Tok
Northway
Tetlin
Boundary
Chicken
Clinton Creek
Rock Creek
Stewart Crossing
Pelly Crossing
Carmacks
Little Salmon
Ross River
Canyon
Champagne
Dezadeash
Marsh Lake
Johnsons Crossing
Jakes Corner
Teslin
Atlin
Tagish
Carcross
Skagway
Haines
Klukwan
Hoonah
Yakutat
Kayak Island
Middleton Island
Montague Island
Seward
Kenai
Soldotna
Homer
Kodiak
Valdez
Cordova
Whittier
Wrangell
Petersburg
Ketchikan
Juneau
Sitka
Craig
Klawock
Hydaburg
Metlakatla
Prince Rupert
Terrace
Kitimat
Stewart
Hazelton
Smithers
Prince George
Dawson Creek
Fort St. John
Fort Nelson
Watson Lake
Whitehorse
Faro
Mayo
Dawson

SECTION 6.0 - INTERCONNECTION ALTERNATIVES AND STUDY CRITERIA

Power flow studies were performed to evaluate the technical feasibility of selected interconnection alternatives of exporting the power available from hydroelectric sites in British Columbia, Alaska and the Northwest Territories to Yukon load centres (see Appendix B).

Following are the transmission distances for the interconnection alternatives.

B.C. to Yukon

Stikine Collector - Whitehorse	465 km
Stikine Collector - Faro	575 km
Liard (Devils Gorge) - Faro	585 km

NWT to Yukon

Bennett Field - Ross River	680 km

Alaska to Yukon

Susitna River - Whitehorse	980 km

Base study criteria include:

1. Projected Yukon load growth as provided by the Yukon River Basin Committee and outlined in the T. Hodge - B. Brickman memo, 14 June 1982, titled "Demand Scenarios for B.C. Hydro". A copy of the memo is included in Appendix D. Three load cases, assuming a load factor of 60 percent, were used in the power flow studies, viz:

Case 1 = 150 MW, consists of approximate existing load + 60 MW additional load.

Case 2 = 300 MW, consists of approximate existing load + 200 MW additional load.

Case 3 = 475 MW, consists of approximate existing load + 400 MW additional load.

No time frame was placed on the load growth.

2. The transmission line voltage would be 500 kV for all alternatives.

3. The interconnection need not be a firm supply; that is, one circuit would suffice if it meets all capacity and voltage requirements.

SECTION 7.0 - TRANSMISSION LINE PLANNING PROCESS FOR REGULATED PROJECTS

In the interest of the province's energy future, the Government of British Columbia introduced an energy policy in February 1980 which established an integrated approach to approval procedures for major energy projects and for removal of energy resources from the province. A booklet, "Guide to the Energy Project Review Process", which describes the requirements of Part 2 of the Utilities Commission Act under which energy projects are reviewed and certified, is included in Appendix C.

Other regulatory agencies would also be involved in a B.C. Hydro application for license to export inter-utility power.

SECTION 8.0 - COST ESTIMATES

8.1 COSTING PROCEDURE

(a) B.C. Interconnection Alternatives

The power flow studies summarized in Section 6.0 and described more fully in Appendix B determined the required interconnection alternatives to be costed, including associated transmission line losses. The construction cost (at 1982 price levels) for each alternative was then calculated using information supplied by B.C. Hydro's Transmission Projects Division and System Engineering Division, and is described in Appendix B.

The comparison of the B.C. alternatives was made on an annual cost basis.

B.C. Hydro annual charges on a transmission project include annual interest and depreciation on the capital cost of the project plus annual operation and maintenance costs. The uniform real annual cost of interest is calculated on the basis of a real interest rate of 4 percent net of inflation. Annual depreciation cost is based on the sinking fund factor with a 4 percent net interest rate over a 45-year lifetime for steel tower transmission lines. The total capital cost of the project includes the construction cost plus an allowance for B.C. Hydro corporate overhead (COH), plus interest during construction (IDC). For the purpose of this study, the COH is estimated at 13 percent of the direct construction cost. IDC is based on a net interest rate of 4 percent and an average of 2 years duration for accumulating this interest.

Annual operating charges, with taxes, are estimated at 2.5 percent of capital cost, excluding overhead.

The resulting total annual fixed costs would be 8.4 percent of the basic construction cost. Table 8-1 summarizes the composition of these annual cost charges for the general case with a basic construction cost of 100.

The total annual cost of line losses, at a load factor of 60 percent, was determined for each B.C. interconnection alternative for an energy cost of losses of 29 mills/kW.h at 4 percent discount rate.

The total annual cost of capital and line losses was then used to calculate the average delivery cost (per kilowatt-hour) of transmission for each load level. The results, cost per kilowatt-hour versus Yukon demand (MW), are plotted on Fig. 8-1.

The selling price of energy would be in addition to the average delivery cost of transmission and would be a negotiated price based on B.C. Hydro long-term energy and capacity values. Present (1982) long-term marginal energy costs are about 30 mills/kW.h.

For economic comparison a sensitivity study, using the above procedure, was conducted with an 8 percent discount rate. The results are shown on Fig. 8-2.

(b) Other Interconnection Alternatives

A total construction cost only was prepared for the Alaska and NWT alternatives, based on a transmission line cost per kilometre value similar to the B.C. alternatives.

8.2 COST OF ALTERNATIVES

Based on total annual charge analysis, a summary of the economic rating of the three B.C. interconnection alternatives is given in Table 8-2. A comparison of average delivery cost of transmission is shown in Table 8-3.

For comparison, Table 8-4 summarizes the total direct transmission costs of the B.C., Alaska and NWT alternatives, relating to the Yukon load level which required the highest cost for each alternative.

TABLE 8-1

ANNUAL COST FACTOR, WITH TAXES, FOR TRANSMISSION LINE PROJECTS
OVER $100 MILLION

Capital Costs	
Direct Construction Cost Index	100.00
Corporate Overhead (13%)	13.00
Construction Cost Plus Overhead	113.00
Interest During Construction (8%)	9.00
TOTAL CAPITAL COST	122.00
Annual Costs	
Interest Charges (4% of Total Capital Cost)	4.88
Depreciation (Sinking Fund) Steel Tower Transmission 45 years, 0.83% of 122.0%	1.01
Operating Costs*1	2.50
TOTAL ANNUAL CHARGES (% of Direct Construction Cost)	8.39% (round off to 8.4%)

*1 Includes operation and maintenance, taxes, insurance, interim replacement, administration and general expense.

B.C. INTERCONNECTION ALTERNATIVES

TABLE 8-2

TOTAL ANNUAL COST SUMMARY

ALTERNATIVE	YUKON LOAD (MW)	DIRECT CAPITAL COST OF TRANSMISSION	ANNUAL COST OF TRANSMISSION	AVERAGE TIE LINE LOSSES (MW)	ANNUAL COST OF LOSSES	TOTAL ANNUAL COST (CAPITAL + LOSSES)
1. Stikine - Whitehorse	150	223281	18756	0.4	102	18858
	300	225271	18923	1.7	432	19355
	475	227346	19097	4.3	1092	20189
2. Liard - Faro	150	265540	22305	0.4	102	22407
	300	270020	22682	2.2	559	23241
	475	273060	22937	5.2	1321	24258
3. Stikine - Faro	150	276541	23229	0.4	102	23331
	300	281021	23606	2.2	559	24165
	475	284061	23861	5.2	1321	25182

All Costs in Thousands of Dollars, 1982 Prices

Annual Charges = 8.4% of Direct Capital Cost

Unit Cost of Losses = 29 mills/kw.h (with taxes)

TABLE 8-3

AVERAGE DELIVERY COST OF TRANSMISSION FOR B.C. INTERCONNECTIONS (1982 DOLLARS)

INTERCONNECTION ALTERNATIVE	YUKON LOAD (MW)	AVERAGE TIE LINE LOSSES (MW)	SENDING END POWER (LOAD + LOSSES)(MW)	SENDING END ENERGY, Es (GW.h/a)	TRANSMISSION ANNUAL CHARGES Ac ($.10^3)	AVERAGE DELIVERY COST OF TRANSMISSION $\frac{Ac}{Es}$ (mills/Kw.h)
1. Stikine - Whitehorse	150	0.4	150.4	791	18858	23.8
	300	1.7	301.7	1586	19355	12.2
	475	4.3	479.3	2519	20189	8.0
2. Liard - Faro	150	0.4	150.4	791	22407	28.3
	300	2.2	302.2	1588	23241	14.6
	475	5.2	480.2	2524	24258	9.6
3. Stikine - Faro	150	0.4	150.4	791	23331	29.5
	300	2.2	302.2	1588	24165	15.2
	475	5.2	480.2	2524	25182	10.0

TABLE 8-4

TOTAL DIRECT TRANSMISSION COSTS OF

B.C., ALASKA AND NWT INTERCONNECTION ALTERNATIVES

INTERCONNECTION ALTERNATIVE	YUKON LOAD LEVEL (MW)	TRANSMISSION LINE	STATIONS	TOTAL DIRECT TRANSMISSION COST
Stikine - Whitehorse	475	192731	34615	227346
Liard - Faro	475	233220	39840	273060
Stikine - Faro	475	244221	39840	284061
NWT - Ross River	150	289000	36440	325440
Alaska - Whitehorse	150	416500	54500	471000

All Costs in Thousands of Dollars, 1982 Prices

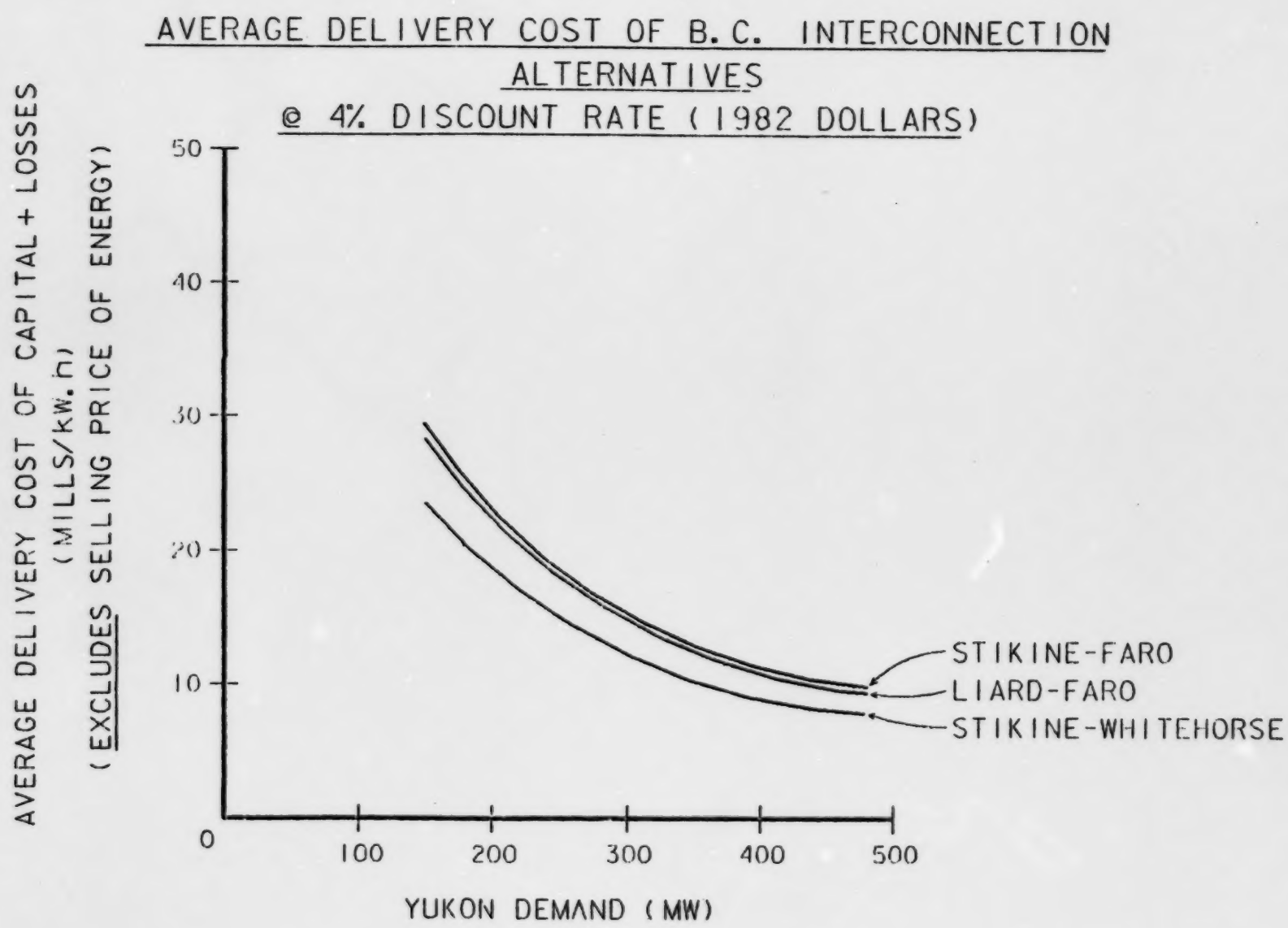

AVERAGE DELIVERY COST OF B.C. INTERCONNECTION ALTERNATIVES @ 4% DISCOUNT RATE (1982 DOLLARS)
AVERAGE DELIVERY COST OF CAPITAL + LOSSES (MILLS/kW.h) (EXCLUDES SELLING PRICE OF ENERGY)
50
40
30
20
10
0
100
200
300
400
500
YUKON DEMAND (MW)
STIKINE-FARO
LIARD-FARO
STIKINE-WHITEHORSE

FIGURE 8-1

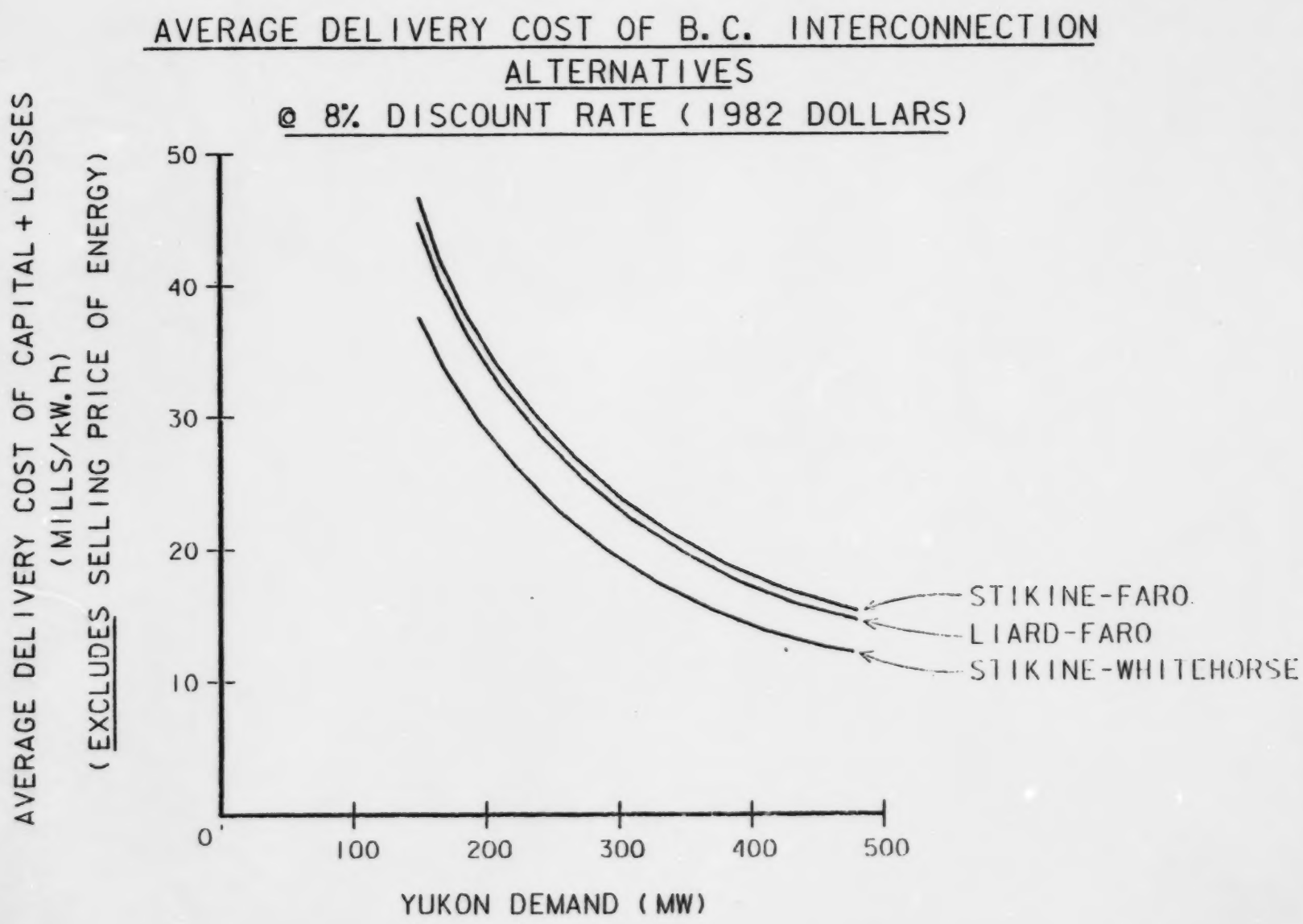

AVERAGE DELIVERY COST OF B.C. INTERCONNECTION ALTERNATIVES
@ 8% DISCOUNT RATE (1982 DOLLARS)
AVERAGE DELIVERY COST OF CAPITAL + LOSSES
(MILLS/kW.h)
(EXCLUDES SELLING PRICE OF ENERGY)
50
40
30
20
10
0
100
200
300
400
500
YUKON DEMAND (MW)
STIKINE-FARO
LIARD-FARO
STIKINE-WHITEHORSE

FIGURE 8-2

APPENDIX A

TERMS OF REFERENCE AND AMMENDMENTS

APPENDIX A

YUKON RIVER BASIN STUDY

ELECTRIC TRANSMISSION INTERCONNECTION STUDY

TERMS OF REFERENCE

SCHEDULE: An Interim Report is required October 31, 1982
The Final Report is required December 31, 1982

INTRODUCTION

The study will address the construction of transmission lines connecting the Whitehorse region load centre to generation sources outside the Yukon. The most likely sources would be those hydroelectric projects now under study in British Columbia: the Yukon-Taku, the Liard, and the Stikine-Iskut but possibilities in Alaska and the Northwest Territories will be checked. The Electric Transmission Interconnection Study will be based on an inventory of all existing and contemplated generation projects in, and within transmission distance of, the Yukon and on forecasts of the electric load growth in the Yukon, particularly in the Whitehorse region. The time frame for this study is the thirty year period 1995 - 2025.

SCOPE

Three electric demand forecasts will be available as input to the study. Transmission interconnections shall be proposed for each of the provided forecasts. An inventory of existing and proposed generating stations will also be available. Transmission interconnections between each station and the Whitehorse region are to be assessed and reported on in the Interim Report. Possible ties to Ross River will also be noted, if applicable. At that stage, interconnection schemes with large economic penalties can be eliminated and only the most attractive schemes will be studies in detail for the Final Report. Transmission interconnection schemes shall be discussed on three levels:

1. General characteristics of interconnections including their reliability, security, and advantages and disadvantages compared to and in conjunction with local hydroelectric development.

2. Technical feasibility of the proposed interconnections including capacity, stability, voltage regulation, losses, and capability of expansion.

3. Economics of interconnection alternatives.

The Transmission Interconnection Study will limit transmission line route location to office study of contour maps and other published information. There is to be no environmental impact study of proposed routes but sensitive areas such as Native Indian Reservations and Provincial or Territorial Parks are to be avoided. A preliminary statement of environmental issues likely to be encountered will be prepared.

STUDY CRITERIA

Transmission distances will be in excess of 450 km in some cases. The ultimate load will be less than 500 MW. These requirements eliminate low-voltage multicircuit lines from consideration and only EHV transmission shall be studied. Direct current transmission should not be considered because neither the capacity or the distance requirements are great enough. The interconnection need not be a firm supply; that is, one circuit will suffice if it meets all capacity and voltage requirements. However, every possible measure that can be taken to ensure that the circuit is reliable as possible should be specified and its cost included.

Simulation studies (load flow, fault, and stability) will be required to assess the following:

1. Voltage levels during normal and emergency operating conditions.

2. Shunt reactor, series capacitor and static var compensator or synchronous condenser requirements.

3. Calculation of losses.

4. Fault levels for station design at receiving (Whitehorse) end.

5. Frequency and voltage excursions during major disturbances in the source system.

6. Stability of the source system.

The study will not require detailed assessment of switching surge or lightning surge effects or the special features which might be needed to reduce those effects. Also the study will not consider detailed optimization of line design beyond an assessment of the minimum conductor size allowable without incurring losses higher than 5% or exceeding radio noise or audible noise standards.

Substation arrangements to a degree of detail suitable for cost estimate purposes shall be determined. One line diagrams of each station arrangement shall be included in the Final Report.

COST ESTIMATES

Cost estimates shall be prepared for each alternative interconnection proposed in the Final Report. The comparison of alternatives shall be on an annual cost basis including levelized cost of capital, annual operating and maintenance costs, and annual cost of losses. This shall be done by applying an annual cost multiplier of 6% to the construction cost of each alternative as derived in Exhibit 1.

FINAL REPORT FORMAT

The Final Report shall include but not necessarily be limited to the following features in addition to the text:

1. Maps of the areas studied, indicating the locations of all generating station sites and transmission line routes.

2. One line diagrams of all substation alternatives.

3. Cross-section sketch to scale of right-of-way for each transmission line voltage considered.

4. One line load flow diagrams indicating real and reactive power flows and bus voltages for each interconnection alternative.

5. Representative swing curves from stability studies.

6. A table of electrical parameters - resistance and impedance of each system element (transmission line, transformer, shunt reactor, etc).

7. Pertinent institutional arrangements will be flagged.

EXHIBIT I

Total Construction Cost Index	100.00	
Corporate Overhead (9 percent)	9.00	
Construction Cost plus Overhead	109.00	
Interest During Construction (9 percent for Transmission)	9.81	
Total Capital Cost	118.81	
Annual Interest Charges (3 percent of Total Capital Cost)	3.56	
Annual Sinking Fund Depreciation (1.079 percent for 45-year Transmission)	1.28	
Annual Operating Costs (0.95 percent of Construction Cost + OH, Transmission)	1.04	
Total Annual Charges (percent of total construction cost)	5.88	(round off to 6%)

AMMENDMENTS TO TERMS OF REFERENCE

AS PER SUBSEQUENT ENERGY WORK GROUP MEETINGS

1. The interim report and final report dates changed to 31 December 1982 and 31 March 1983, respectively.

2. No time frame place on the load growth.

3. Items 2, 4, 5 and 6 of the final report format removed.

AS PER PRESENT B.C. HYDRO PRACTICE

1. The standard discount rate changed to 4 percent.

2. The total annual charge multiplier changed to 8.4 percent of direct construction cost. Exhibit 1 revised to reflect the change in Exhibit 1-R1.

3. An 8 percent discount rate used in the sensitivity calculation.

EXHIBIT 1-R1

ANNUAL COST FACTOR, WITH TAXES, FOR
TRANSMISSION LINE PROJECTS OVER $100 MILLION

Capital Costs	
Direct Construction Cost Index	100.0
Corporate Overhead (13%)	13.0
Construction Cost plus Overhead	113.0
Interest During Construction (8%)	9.0
Total Capital Cost	122.0
Annual Costs	
Interest Charges (4% of Total Capital Cost)	4.88
Depreciation (Sinking Fund) Steel Tower Transmission 45-year, 0.83% of 122.0%	1.01
Operating Costs*1	2.5
Total Annual Charges (percent of direction construction cost)	8.39% (round off to 8.4%)

*1 Includes operation and maintenance, taxes, insurance, interim replacement, administration and general expense.

APPENDIX B

POWER FLOW AND COST STUDIES

APPENDIX B
POWER FLOW AND COST STUDIES

CONTENTS

Section	Subject	Page
B.1	TRANSMISSION INTERCONNECTION ALTERNATIVES	B - 1
B.2	TECHNICAL STUDIES	B - 4
B.3	POWER FLOW RESULTS	B - 6
B.4	COST ESTIMATES	B - 9

TABLES

Table No.	
B-1	Power Flow Summary - Stikine to Whitehorse 500 kV Interconnection (B.C. Hydro Winter Peak Load)
B-2	Power Flow Summary - Stikine to Whitehorse 500 kV Interconnection (B.C. Hydro Summer Light Load)
B-3	Power Flow Summary - Liard to Faro 500 kV Interconnection (B.C. Hydro Winter Peak Load)
B-4	Power Flow Summary - Liard to Faro 500 kV Interconnection (B.C. Hydro Summer Light Load)
B-5	Power Flow Summary - Bennett Field to Ross River 500 kV Interconnection
B-6	Power Flow Summary - Susitna River to Whitehorse 500 kV Interconnection
B-7	Construction Cost Estimates for B.C. Interconnection Alternatives

CONTENTS - (Cont'd)

FIGURES

Figure No.	
B-1	Typical 500 kV Lattice Steel Tower Outlines
B-2	Preliminary Right-of-Way Cross Section for 500 kV Transmission Lines

APPENDIX B
POWER FLOW AND COST STUDIES

B.1 TRANSMISSION INTERCONNECTION ALTERNATIVES

(a) Stikine - Whitehorse 500 kV Line

There are four proposed hydroelectric generation sites on the Stikine-Iskut River Basin as shown in Fig. 4-1 of the main report. These are Iskut Canyon on the Iskut River, a site on More Creek just upstream of its confluence with the Iskut River, and Stikine Canyon and Tanzilla on the Stikine River. These developments could provide approximately 2800 MW of generating capacity, 935 MW from Iskut Canyon and More Creek and 1830 MW from the two Stikine sites. The Stikine projects are located approximately 500 km north of the nearest point on the existing provincial electric grid and 1400 km from Vancouver.

For an interconnection to the Yukon, this alternative assumes a line between Stikine Collector and Whitehorse, a distance of 465 km. The Stikine Collector substation would be located close to Stikine Canyon generating plant to serve as a collector for both the Stikine Canyon and Tanzilla power outputs. An intermediate switching station would be required at the approximate midpoint of the line to reduce switching overvoltages. The preliminary route study plan is shown on Fig. 5-1 of the main report. From Stikine Canyon the transmission line route heads west alongside the Stikine River past Tanzilla before turning northwest through the Taya, Nahlin and Teslin river systems. The route continues along the east side of Teslin Lake to Johnsons Crossing where it then follows the Alaska Highway corridor to Whitehorse.

(b) Liard - Faro 500 kV Line

The presently proposed Liard River generating plants at Devils Gorge (2490 MW) and Beavercrow (1920 MW) would have a total installed capacity of 4410 MW. These two sites are located approximately 750 km from the nearest point on the existing grid and 1380 km from Vancouver.

A tie-line from Devils Gorge to Faro, a distance of 585 km, is considered. Again an intermediate switching station would be required at the approximate midpoint of the line to reduce switching overvoltages. This line route proceeds westerly from Devils Gorge along the Alaska Highway alignment to Watson Lake townsite where it then follows the Robert Campbell Highway all the way to Faro. The preliminary route study plan is shown on Fig. 5-2 of the main report.

(c) Stikine - Faro 500 kV Line

Power flow studies were not conducted on this alternative as the route length (575 km) is almost equidistant to that of the Liard - Faro line. Therefore the results of the Liard - Faro power flow studies may also be used for this case. The routing from Stikine Collector is the same as for the Stikine - Whitehorse interconnection to Johnsons Crossing. From this point the route heads north along the Canol Road alignment to Ross River, then turns northwest following the Robert Campbell Highway to Faro. Reference Fig. 5-1 of the main report.

(d) Bennett Field - Ross River 500 kV Line

In the Northwest Territories a 600 MW development in three projects is being considered for potential power sites located on the Great Bear River, east of Fort Norman. Due to lack of knowledge of the

project locations, for the purpose of this study the point of connection is assumed to be at Bennett Field.

The transmission route from Bennett Field has been assumed to follow the Canol Road to the Yukon border and to continue on to Ross River for a total distance of approximately 680 km. An intermediate switching station would be required.

The assumed power site and transmission line route are shown on Fig. 5-4 of the main report.

(e) Susitna River - Whitehorse 500 kV Line

The development of the Susitna River in Alaska has been studied since 1979 by Acres American Incorporated, engaged by the Alaska Power Authority. For an interconnection to the Yukon the point of connection in Alaska has been assumed to be the upstream site on the Susitna River. The potential capacity appears to be approximately 1200 MW in two projects.

An interconnection to Whitehorse would require a 980 km line with two intermediate switching stations located at approximately one-third and two-thirds of the line length in order to reduce switching overvoltages.

The line route from Susitna River would generally follow a southeast direction to the vicinity of Glennallen and then proceed alongside the Tok Highway to Tok townsite. From Tok, the route would run south down the Alaska Highway to Whitehorse.

The assumed generating site and transmission line route are shown on Fig. 5-5 of the main report.

B.2 TECHNICAL STUDIES

(a) Procedure

Cases which satisfied basic transmission requirements were developed with interconnections at 500 kV between generation sources outside the Yukon and regional load centres within the Yukon River Basin. Four possible generation sources were identified as described in Section B.1 of this appendix. Each interconnection alternative was considered in turn to determine its technical feasibility and economic viability.

Power flow simulations were performed to evaluate the technical feasibility of each alternative. These simulations assessed the following aspects:

1. 500 kV tie-line voltage levels during normal operating conditions for various Yukon load levels;

2. shunt compensation requirements for voltage control purposes; and

3. calculation of tie-line losses.

The proposed integrated B.C. Hydro 500 kV system (post year 2000) was represented in detail for the B.C. - Yukon interconnections with winter peak and summer light load conditions being investigated to establish acceptable 500 kV voltage levels in the B.C. Hydro system. Due to the preliminary nature of the study, The Yukon Electrical Company Limited electric system was not represented as its effect on the major parameters of the study would be negligible.

For the B.C. - Yukon interconnection alternatives, a base case without a tie-line was run initially to establish acceptable 500 kV voltage levels in the Stikine and Liard transmission systems. The voltage levels were then held constant throughout a succession of line loadings for each alternative by selective control of Stikine and Liard generation and shunt compensation. The intermediate and Yukon receiving end 500 kV bus voltages were maintained at 1.070 per unit (535 kV) by appropriate amounts of shunt compensation. The Alaska and NWT interconnection alternatives assumed an arbitrary flat voltage profile over the interconnection with the sending end, intermediate and Yukon receiving end 500 kV substation voltages held constant at 1.07 per unit (535 kV) by use of appropriate shunt compensation and sending end generation.

Costs were calculated for the transmission alternatives and a comparison of the B.C. alternatives prepared on an annual cost basis.

(b) Yukon Demand Forecast

The Yukon load levels which provide a framework for the Transmission Interconnection Study are described in Appendix D. From Fig. 1 of this memo, three load cases were determined for use in the power flow studies.

Case 1 = 150 MW, consists of existing load + 60 MW additional load.

Case 2 = 300 MW, consists of existing load + 200 MW additional load.

Case 3 = 475 MW, consists of existing load + 400 MW additional load.

In order to assess the effect of the load power factor on shunt reactive compensation requirements, power flow studies were carried out at unity and 0.95 lag power factors. Representation of the Yukon load is a lumped equivalent on the 500 kV Yukon receiving end bus (that is, Whitehorse, Faro or Ross River) depending on the respective interconnection alternative.

(c) Transmission Parameters

The study does not consider detailed optimization of line design beyond an assessment of the minimum conductor size allowable without incurring losses higher than 5 percent or exceeding radio noise or audible noise standards. The transmission line impedances represent a tower design and conductor size used extensively in the B.C. Hydro 500 kV system.

Structure configurations and right-of-way requirements for a 500 kV single circuit transmission line based on present conventional tower design are shown on Figs. B-1 and B-2, respectively.

B.3 POWER FLOW RESULTS

The results of the power flow studies are presented and discussed for each interconnection alternative. With the exception of shunt reactors, no attempt was made to optimize reactive power flow. Satisfactory operation of the interconnection was maintained by selective choice of reactor sizes and location.

A list of the power flows performed is given in Tables B-1 to B-6.

(a) Stikine - Whitehorse 500 kV Line

This alternative has the shortest transmission line distance. Power flow studies included B.C. Hydro winter peak and summer light load system conditions. The 465 km interconnection would require an intermediate switching station between Stikine Collector substation and Whitehorse. Maximum shunt reactor compensation requirements include 272 Mvar at Stikine Collector, 230 Mvar at the intermediate switching station, and 145 Mvar at Whitehorse. Fifty Mvar of capacitors are also required at Whitehorse. The Stikine Canyon generators operate at small lagging power factor under winter peak load and at small leading power factor for summer light load conditions. The largest 500 kV voltage angle across the interconnection is 15°. The peak tie-line losses are 1 MW, 4 MW and 10 MW for line loadings of 150 MW, 300 MW and 475 MW respectively. For summer light load conditions, additional shunt reactor compensation requirements within the B.C. Hydro system due to the interconnection amount to 145 Mvar. Power flow summaries are given in Tables B-1 and B-2.

(b) Liard - Faro 500 kV Line

Power flow studies were carried out under B.C. Hydro system winter peak and summer light load conditions. This alternative would require a 585 km transmission line between Devils Gorge generating station and Faro with an intermediate switching station at the approximate line midpoint. Maximum shunt reactor compensation needs are 250 Mvar at Devils Gorge, 317 Mvar at the intermediate station, and 183 Mvar at Faro. Nineteen Mvar of capacitors are also required at Faro. The operating power factor of Devils Gorge generators are slightly lagging for peak load conditions and slightly leading for light load conditions. The peak tie-line losses are 1 MW, 5 MW and 12 MW for the three respective line loadings. The largest angle across the interconnection is 19°.

Within the B.C. Hydro system, 233 Mvar of additional shunt reactors would be needed to compensate for the interconnection. Power flow summaries are given in Tables B-3 and B-4.

(c) Stikine - Faro 500 kV Line

No power flows were performed on this alternative as the route distance (575 km) is practically the same as the Liard - Faro line and therefore the same results are applicable.

(d) Bennett Field (NWT) - Ross River 500 kV Line

The length of this interconnection (680 km) is greater than any of the B.C. alternatives. One intermediate switching station would be required between Bennett Field and Ross River. Due to lack of data, this case was looked at in only a superficial manner with respect to power flow analysis. The total shunt reactor requirement associated with the tie-line is 836 Mvar, tie-line losses are 1 MW, 5 MW and 14 MW for the three respective load levels and the angle across the interconnection for the 475 MW load is 22°. A summary of the power flows is shown in Table B-5.

(e) Susitna River (Alaska) - Whitehorse 500 kV Line

This interconnection is the longest (980 km) of all the alternatives and requires two intermediate stations between Susitna River generating site and Whitehorse. The total amount of shunt reactor compensation is 1222 Mvar, tie-line losses are 2 MW, 8 MW and 20 MW for the three respective load levels, and there is an angle of 32° over the interconnection for 475 MW line loading. The power flow summary is given in Table B-6.

B.4 COST ESTIMATES

(a) Sources of Information

(i) Transmission

A construction cost estimate and schedule were obtained from B.C. Hydro's Transmission Project Division for the Liard and Stikine 500 kV transmission interconnections. A detailed cost for the preliminary assessment, public consultation, detailed studies and the application and project review has not been provided.

Table B-7 indicates uninflated annual cash flow (in 1982 dollars) coinciding with the construction schedule, Fig. 5-3 of the main report. Access costs are included within the cost shown for construction.

Allowances have been made for construction in remote areas and a factor is included for foundation installation in areas identified as being possible muskeg and permafrost. An allowance is also made for the extra cost in tower erection and stringing due to difficult access and climate conditions experienced in northern B.C. and the Yukon.

Estimates for the Alaska and Northwest Territories interconnections are based on a construction cost of $425,000/km, similar to the Stikine - Faro line. These estimates may therefore require increasing due to the more hazardous terrain, isolation and harsher climates.

(ii) Stations

Substation costs, in 1982 dollars, were determined from information supplied by B.C. Hydro's Station Planning Department. The station costs for the Yukon 500 kV line terminations reflect only basic substation elements (circuit breakers and line terminals) plus required amounts of shunt compensation. Some provision for site acquisition and special consideration for the remoteness of the intermediate substations has been factored into the cost estimates, based on allowances made for B.C. Hydro's proposed Devils Gorge and Stikine Collector stations.

The Alaska and NWT 500 kV sending end stations and all intermediate switching station estimates are based on B.C. Hydro's unit cost prices. Generator-transformer and low voltage switching costs are not included.

(b) Cost of Interconnection Alternatives

A cost estimate has been prepared for all alternatives proposed in the report. The total construction cost determined for each B.C. alternative was multiplied by 8.4 percent to obtain a comparison of the total annual charges.

The total annual cost of capital, losses and other annual charges was used to develop an average delivery cost per kilowatt-hour for the B.C. alternatives. This is the average cost of the capital, the operating expenses, and the losses expressed as a function of the demand at the Yukon (receiving) end. It does not include the selling price of energy (see Section 8.1).

Section 8.0 of the main report contains a detailed cost summary of the B.C. - Yukon interconnection schemes.

(British Columbia - Yukon)

Stikine - Whitehorse 500 kV Interconnection

Power Flow Summary

B.C. Hydro System Winter Peak Load

Table B-1

Power Flow #	System Conditions	Stikine Canyon Gen. Voltage (p.u.) on 13.8kV	Stikine Canyon Gen. Output-MW(MVAR)	Stikine Collector 500kV Voltage[1]	Stikine Collector 500kV Shunt[2] Comp.	Inter. Sub 500kV Voltage[1]	Inter. Sub 500kV Shunt[2] Comp.	Whitehorse 500kV Voltage[1]	Whitehorse 500kV Shunt[2] Comp.	Whitehorse 500kV Load MW(MVAR)	Tie Line Losses (MW)	Stikine-Whitehorse Angle(°)
1	Base case, B.C. Hydro System without Yukon Tie	1.027	915(73)	1.050	-245	--	--	--	--	--	--	--
2	Stikine Collector - Whitehorse 500 kV tie line I/S Whitehorse load = 0 MW	1.028	915(81)	1.050	-368	1.070	-230	1.070	-145	0	0	0
3	As 2 but with Whitehorse load = 150 MW @ 1.0 p.f.	1.017	915(0)	1.050	-368	1.070	-225	1.070	-133	150(0)	1	4.8
4	As 2 but with Whitehorse load = 150 MW @ 0.95 p.f.	1.018	915(9)	1.050	-443	1.070	-225	1.070	-90	150(50)	1	4.8
5	As 2 but with Whitehorse load = 300 MW @ 1.0 p.f.	1.018	915(0)	1.050	-517	1.070	-207	1.070	-115	300(0)	4	9.5
6	As 2 but with Whitehorse load = 300 MW @ 0.95 p.f.	1.019	915(17)	1.050	-517	1.070	-207	1.070	-28	300(100)	4	9.5
7	As 2 but with Whitehorse load = 475 MW @ 1.0 p.f.	1.023	915(50)	1.050	-517	1.070	-174	1.070	-87	475(0)	10	15.1
8	As 2 but with Whitehorse load = 475 MW @ 0.95 p.f.	1.024	915(56)	1.050	-517	1.070	-174	1.070	+50	475(156)	10	15.1

[1] bus voltage (per unit) on 500 kV base

[2] reactive power compensation (MVAR) on 500 kV base
(- shunt reactors)
(+ shunt capacitors)

(British Columbia - Yukon)

Stikine - Whitehorse 500 kV Interconnection

Power Flow Summary

B.C. Hydro System Summer Light Load

Table B-2

Power Flow #	System Conditions	Stikine Canyon Gen. Voltage (p.u.) on 13.8kV	Stikine Canyon Gen. Output MW(MVAR)	Stikine Collector 500kV Voltage[1]	Stikine Collector 500kV Shunt[2] Comp.	Inter. Sub 500kV Voltage[1]	Inter. Sub 500kV Shunt[2] Comp.	Whitehorse 500kV Voltage[1]	Whitehorse 500kV Shunt[2] Comp.	Whitehorse 500kV Load MW(MVAR)	Tie Line Losses (MW)	Stikine-Whitehorse Angle(°)
11	Base case, B.C. Hydro System without Yukon Tie.	1.020	450(13)	1.050	-245	--	--	--	--	--	--	--
12	Stikine Collector - Whitehorse 500 kV Tie Line I/S Whitehorse Load = 0 MW	1.017	450(2)	1.050	-443	1.070	-230	1.070	-145	0	0	0
13	As 12 but with Whitehorse load = 150 MW @ 1.0 p.f.	1.012	450(-16)	1.050	-443	1.070	-224	1.070	-133	150(0)	1	4.8
14	As 12 but with Whitehorse load = 150 MW @ 0.95 p.f.	1.012	450(-16)	1.050	-443	1.070	-224	1.070	-89	150(50)	1	4.8
15	As 12 but with Whitehorse load = 300 MW @ 1.0 p.f.	1.010	450(-24)	1.050	-443	1.070	-208	1.070	-114	300(0)	4	9.5
16	As 12 but with Whitehorse load = 300 MW @ 0.95 p.f.	1.010	450(-24)	1.050	-443	1.070	-208	1.070	-28	300(100)	4	9.5
17	As 12 but with Whitehorse load = 475 MW @ 1.0 p.f.	1.010	450(-25)	1.050	-443	1.070	-174	1.070	-87	475(0)	10	15.1
18	As 12 but with Whitehorse load = 475 MW @ 0.95 p.f.	1.010	450(-25)	1.050	-443	1.070	-174	1.070	+50	475(156)	10	15.1

[1] bus voltage (per unit) on 500 kV base

[2] reactive power compensation (MVAR) on 500 kV base
(- shunt reactors)
(+ shunt capacitors)

(British Columbia - Yukon)

Liard - Faro 500 kV Interconnection

Power Flow Summary

B.C. Hydro System Winter Peak Load

Table B-3

Power Flow #	System Conditions	Devils Gorge Gen. Voltage (p.u.) on 13.8kV	Devils Gorge Gen. Output MW(MVAR)	Devils Gorge 500kV Voltage[1]	Devils Gorge 500kV Shunt[2] Comp.	Midpoint Stn 500kV Voltage[1]	Midpoint Stn 500kV Shunt[2] Comp.	Faro 500kV Voltage[1]	Faro 500kV Shunt[2] Comp.	Load MW(MVAR)	Tie Line Losses (MW)	Liard-Faro Angle(°)
21	Base case, B.C. Hydro System without Yukon Tie	1.027	2490(205	1.050	-368	--	--	--	--	--	--	--
22	Devils Gorge - Faro 500 kV Tie Line in-service. Faro load = 0 MW	1.022	2490(85)	1.050	-490	1.070	-317	1.070	-183	0	0	0
23	As 22 but with Faro Load = 150 MW @ 1.0 p.f.	1.019	2490(5)	1.050	-490	1.070	-311	1.070	-169	150(0)	1	6
24	As 22 but with Faro load = 150 MW @ 0.95 p.f.	1.018	2490(5)	1.050	-490	1.070	-310	1.070	-126	150(50)	1	6
25	As 22 but with Faro load = 300 MW @ 1.0 p.f.	1.018	2490(9)	1.050	-570	1.071	-287	1.071	-149	300(0)	5	12
26	As 22 but with Faro load = 300 MW @ 0.95 p.f.	1.019	2490(15)	1.050	-570	1.070	-289	1.070	-62	300(100)	5	12
27	As 22 but with Faro load = 475 MW @ 1.0 p.f.	1.018	2490(0)	1.050	-613	1.070	-246	1.070	-117	475(0)	12	19.1
28	As 22 but with Faro load = 475 MW @ 0.95 p.f.	1.018	2490(3)	1.050	-613	1.070	-246	1.070	+19	475(156)	12	19.1

[1] bus voltage (per unit) on 500 kV base

[2] reactive power compensation (MVAR) on 500 kV base
(- shunt reactors)
(+ shunt capacitors)

(British Columbia - Yukon) Liard - Faro 500 kV Interconnection

Power Flow Summary B.C. Hydro System Summer Light Load Table B-4

Power Flow #	System Conditions	Devils Gorge Gen. Voltage (p.u.) on 13.8kV	Devils Gorge Gen. Output MW(MVAR)	Devils Gorge 500kV Voltage[1]	Devils Gorge 500kV Shunt[2] Comp.	Midpoint Stn 500kV Voltage[1]	Midpoint Stn 500kV Shunt[2] Comp.	Faro 500kV Voltage[1]	Faro 500kV Shunt[2] Comp.	Load MW(MVAR)	Tie Line Losses (MW)	Liard-Faro Angle(°)
31	Base Case, B.C. Hydro System without Yukon Tie	1.014	1300(-39)	1.050	-368	--	--	--	--	--	--	--
32	Devils Gorge - Faro 500 kV Tie Line in-service. Faro load = 0 MW	1.011	1300(-73)	1.050	-568	1.070	-317	1.070	-183	0	0	0
33	As 32 but with Faro load = 150 MW @ 1.0 p.f.	1.009	1300(-97)	1.050	-568	1.070	-311	1.070	-169	150(0)	1	6
34	As 32 but with Faro load = 150 MW @ 0.95 p.f.	1.008	1300(-106)	1.050	-568	1.070	-310	1.069	-126	150(50)	1	6
35	As 32 but with Faro load = 300 MW @ 1.0 p.f.	1.010	1300(-86)	1.050	-618	1.070	-289	1.070	-149	300(0)	5	12
36	As 32 but with Faro load = 300 MW @ 0.95 p.f.	1.010	1300(-84)	1.050	-618	1.070	-289	1.070	-62	300(100)	5	12
37	As 32 but with Faro load = 475 MW @ 1.0 p.f.	1.009	1300(-93)	1.050	-618	1.070	-246	1.070	-117	475(0)	12	19.1
38	As 32 but with Faro load = 475 MW @ 0.95 p.f.	1.009	1300(-93)	1.050	-618	1.070	-246	1.070	+19	475(156)	12	19.1

[1] bus voltage (per unit) on 500 kV base

[2] reactive power compensation (MVAR) on 500 kV base
(- shunt reactors)
(+ shunt capacitors)

(Northwest Territories - Yukon) Bennett Field - Ross River 500 kV Interconnection

Table B-5

Power Flow Summary

Power Flow #	System Conditions	Bennett Field Gen.		Bennett Field 500kV		Inter. Sub 500kV		Ross River 500 kV			Tie Line Losses (MW)	Bennett F Ross R. Angle($^{\circ}$)
		Voltage (p.u.) on 13.8kV	Output MW(MVAR)	Voltage[1]	Shunt[2] Comp.	Voltage[1]	Shunt[2] Comp.	Voltage[1]	Shunt[2] Comp.	Load MW(MVAR)		
41	Bennet Field - Ross R. 500 kV Tie Yukon Load = 0 MW	1.040	0(-16)	1.069	-200	1.070	-423	1.070	-213	0	0	0
42	As 41 with Yukon Load = 150 MW @ 1.0 p.f.	1.040	151(-16)	1.070	-200	1.070	-417	1.070	-200	150(0)	1	7
43	As 41 with Yukon Load = 150 MW @ 0.95 p.f.	1.040	151(-17)	1.070	-200	1.070	-417	1.070	-155	150(50)	1	7
44	As 41 with Yukon Load = 300 MW @ 1.0 p.f.	1.040	305(-5)	1.069	-200	1.070	-390	1.070	-177	300(0)	5	13.8
45	As 41 with Yukon Load = 300 MW @ 0.95 p.f.	1.040	305(-4)	1.069	-200	1.070	-390	1.070	-90	300(100)	5	13.8
46	As 41 with Yukon Load = 475 MW @ 1.0 p.f.	1.035	489(-17)	1.069	-150	1.070	-342	1.070	-140	475(0)	14	21.9
47	As 41 with Yukon Load = 475 MW @ 0.95 p.f.	1.035	489(-17)	1.069	-150	1.070	-342	1.070	0	475(156)	14	21.9

[1] Bus voltage (per unit) on 500 kV base.

[2] reactive power compensation (MVAR) on 500 kV base
(-shunt reactors)
(+shunt capacitors)

(Alaska - Yukon)

Susitna River - Whitehorse 500 kV Interconnection

Power Flow Summary

Table B-6

Power Flow #	System Conditions	Susitna R. Gen. Voltage (p.u.) on 13.8kV	Susitna R. Gen. Output MW(MVAR)	Susitna R. 500kV Voltage[1]	Susitna R. 500kV Shunt[2] Comp.	Sub 1 500kV Voltage[1]	Sub 1 500kV Shunt[2] Comp.	Sub 2 500kV Voltage[1]	Sub 2 500kV Shunt[2] Comp.	Ross River 500kV Voltage[1]	Ross River 500kV Shunt[2] Comp.	Ross River 500kV Load MW(MVAR)	Tie Line Losses (MW)	Susitna-Whitehorse Angle(°)
51	Susitna R. - Whitehorse 500 kV Tie Yukon Load = 0 MW	1.040	0(-10)	1.068	-200	1.070	-409	1.070	-409	1.071	-204	0	0	0
52	As 51 with Yukon Load = 150 MW @ 1.0 p.f.	1.040	152(-10)	1.069	-200	1.070	-398	1.070	-401	1.070	-190	150(0)	2	9.8
53	As 51 with Yukon Load = 150 MW @ 0.95 p.f.	1.040	152(-10)	1.068	-200	1.069	-398	1.069	-401	1.069	-147	150(50)	2	9.8
54	As 51 with Yukon Load = 300 MW @ 1.0 p.f.	1.040	308(1)	1.068	-200	1.071	-370	1.071	-378	1.071	-170	300(0)	8	19.8
55	As 51 with Yukon Load = 300 MW @ 0.95 p.f.	1.042	308(6)	1.069	-200	1.069	-375	1.069	-377	1.069	-82	300(100)	8	19.8
56	As 51 with Yukon Load = 475 MW @ 1.0 p.f.	1.042	495(21)	1.069	-175	1.069	-326	1.069	-330	1.069	-135	475(0)	20	31.8
57	As 51 with Yukon Load = 475 MW @ 0.95 p.f.	1.042	495(20)	1.069	-175	1.070	-326	1.070	-330	1.070	0	475(156	20	31.8

[1] Bus voltage (per unit) on 500 kV base.

[2] reactive power compensation (MVAR) on 500 kV base
(- shunt reactors)
(+ shunt capacitors)

YUKON INTERCONNECTION STUDY

TABLE B-7

Estimates for Alternative Routes
Cash Flow in $'000

STIKINE TO WHITEHORSE - 465 km (Fig. 5-1)

	6	5	4	3	2	1	0	TOTAL
Engineering & Expenses	1,000	1,600	1,600	1,500	1,500	1,500	1,080	9,780
Material Handling & Yarding	400	400	400	400	600	623		2,823
Clearing		6,510	6,510					13,020
Materials		2,500	2,900	11,540	13,540	14,200	11,040	55,720
Construction			12,870	16,000	18,880	28,250	10,250	86,250
Contingency	210	1,651	3,642	4,416	5,178	6,686	3,355	25,138
TOTAL	1,610	12,661	27,922	33,856	39,698	51,259	25,725	192,731

Cost per km = $414,000

LIARD (DEVIL'S GORGE) TO FARO - 585 km (Fig. 5-2)

	6	5	4	3	2	1	0	TOTAL
Engineering & Expenses	1,000	1,700	1,700	1,500	1,500	1,600	1,150	10,150
Material Handling & Yarding	500	500	500	500	800	643		3,443
Clearing		10,254	10,254					20,508
Materials		3,200	3,400	13,660	15,070	20,000	14,000	69,330
Construction			17,370	20,000	20,000	31,000	11,000	99,370
Contingency	225	2,348	4,983	5,349	5,605	7,987	3,922	30,419
TOTAL	1,725	18,002	38,207	41,009	42,975	61,230	30,072	233,220

Cost per km = $399,000

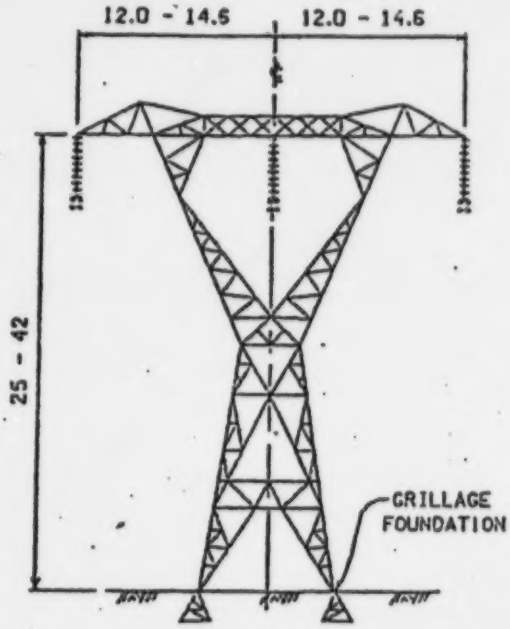
STIKINE TO FARO - 575 km (Fig. 5-1)

	6	5	4	3	2	1	0	TOTAL
Engineering & Expenses	1,200	2,000	2,000	1,700	1,700	1,600	1,490	11,690
Material Handling & Yardage	500	500	500	500	800	672		3,472
Clearing		8,050	8,050					16,100
Materials		3,500	3,600	14,000	16,000	18,000	13,590	68,690
Construction			16,000	20,071	25,000	38,340	13,003	112,414
Contingency	255	2,107	4,522	5,440	6,525	8,791	4,215	31,855
TOTAL	1,955	16,157	34,672	41,711	50,025	67,403	32,298	244,221

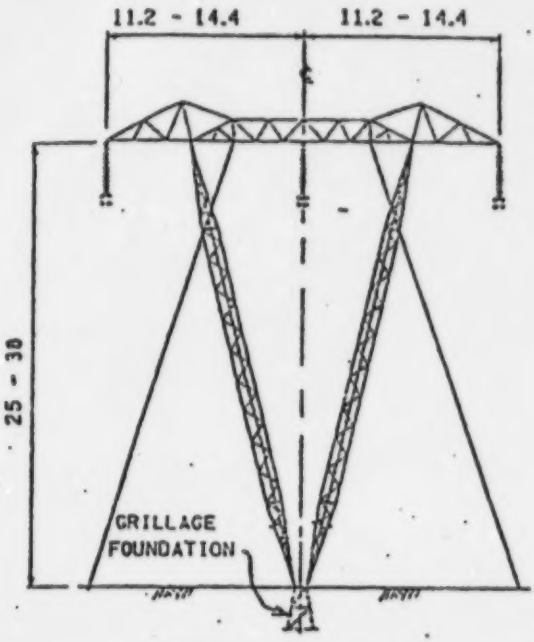
Cost per km = $425,000

NOTE: A fifteen percent contingency was applied to the totals to allow for limited knowledge of route location and design requirements.

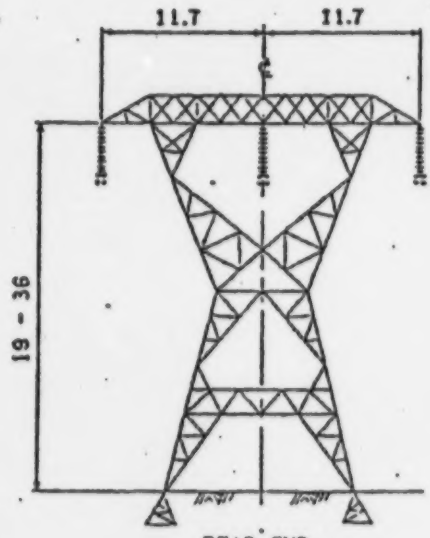
Summary of Costs: Stikine to Whitehorse - $192,731,000 representing a cost of $414,000/km
Liard (Devil's Gorge) to Faro - $233,221,000 " " " $399,000/km
Stikine to Faro - $244,220,000 representing a cost of $425,000/km



TANGENT & LIGHT ANGLE
(SELF SUPPORTING TOWER)



TANGENT & LIGHT ANGLE
(GUYED TOWER)

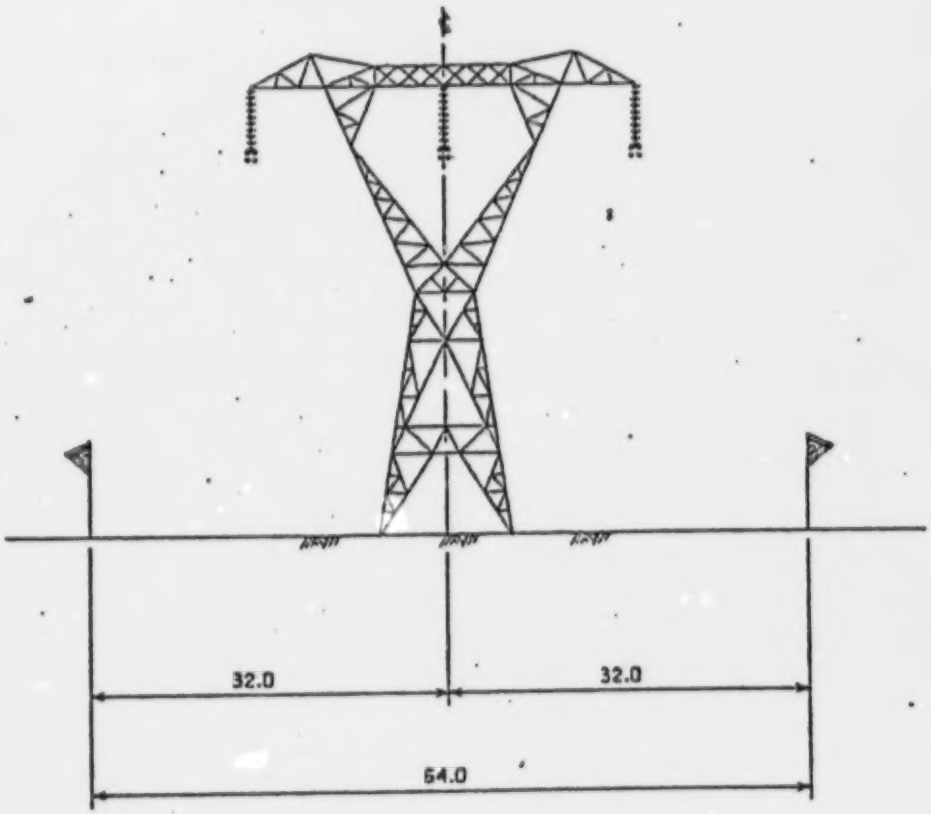


DEAD END
(SELF SUPPORTING TOWER)

NOTE:

ALL DIMENSIONS ARE IN METRES.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY	
HIGH VOLTAGE TRANSMISSION LINES TYPICAL 500 kV LATTICE STEEL TOWER OUTLINES	
DATE	FIGURE B-1
DWN.	



NOTES:

1. DIMENSIONS ARE PRELIMINARY ONLY AND MAY VARY ACCORDING TO TERRAIN.
2. ALL DIMENSIONS ARE IN METRES.

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY	
HIGH VOLTAGE TRANSMISSION LINES PRELIMINAY RIGHT OF WAY CROSS SECTIONS	
DATE	FIGURE B-2
DWN.	

APPENDIX C

GUIDE TO ENERGY PROJECT REVIEW PROCESS

APPENDIX C

Guide to the Energy Project Review Process

Province of British Columbia

Ministry of Energy, Mines and Petroleum Resources

ENERGY RESOURCES DIVISION
PROJECT ANALYSIS BRANCH

Guide to the Energy Project Review Process

Province of British Columbia

Ministry of Energy, Mines and Petroleum Resources

ENERGY RESOURCES DIVISION
PROJECT ANALYSIS BRANCH

January, 1982

Published January, 1982

Energy Resources Division
Project Analysis Branch
Ministry of Energy, Mines and Petroleum Resources
Parliament Buildings
Victoria, B.C. V8V 1X4

Canadian Cataloguing in Publication Data
Main entry under title:
Guide to the energy project review process

Bibliography: p. 00
ISBN 0-7719-8843-5

1. Energy development — Law and legislation — British Columbia. 2. Energy policy — British Columbia. 3. British Columbia. Utilities Commission Act. I. British Columbia. Energy Resources Division. Project Analysis Branch.

KEB376.A72E56 346.71104'679 C82-092037-1

Contents

Introduction 4

Part One: Legislation and Administration

Legislative Requirements 5
Regulated Projects 5
Application Procedures 6
Review Procedures 6
Administration 8
Energy Project Coordinating Committee 8
Working Committees 8
Relationship to Other Project Review Procedures 8

Part Two: Application Requirements

The Application Process 10
Pre-Application Phase 10
Prospectus 10
Preliminary Planning Report 11
Application 12
Applicant 12
Project Description 12
Environmental and Socio-Economic Impact Assessment 13
Project Justification 13
Ancillary Applications 14
Public Consultation 15
Other Information 15
Submission of Application 16
Disposition of Application 16

Appendices

Appendix 1: Utilities Commission Act, Part 2; B.C. Regulation 388/80. 19

Appendix 2: Information Requirements 23
1. Project Justification 23
2. Site and Route Selection Process 24
3. Biophysical and Land Use Information 25
4. Socio-Economic Information 26

Appendix 3: Provincial Statutes 27

Appendix 4: Bibliography 32

Figures

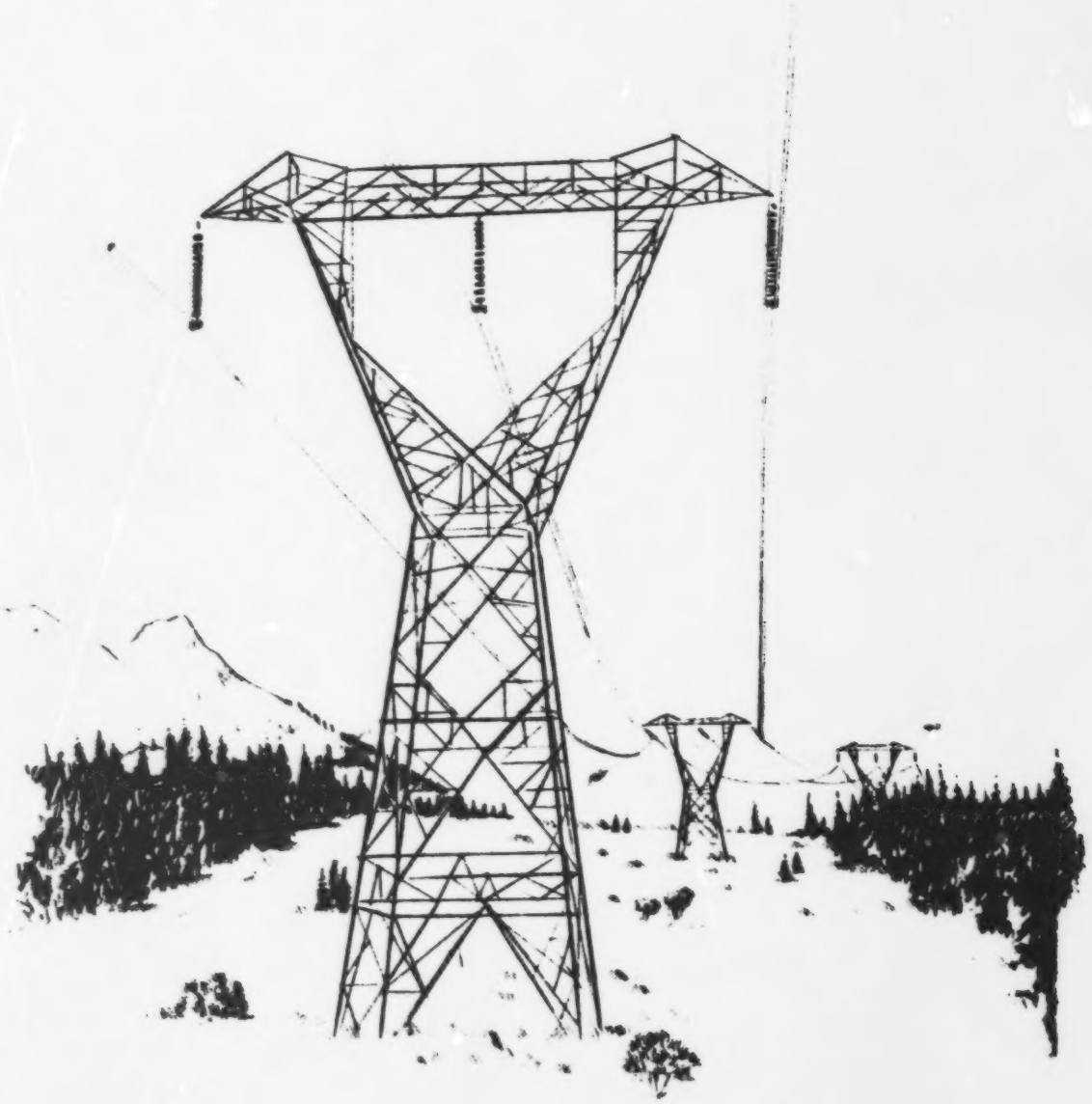
Figure 1 Certification Procedures 7
Figure 2 Inter-Agency Framework 9
Figure 3 Energy Project Application Process 11
Figure 4 Resource Management Regions 15

Introduction

Energy is one of British Columbia's most important resources. Its use and development is of vital public concern. In the interest of the province's energy future, the Government of British Columbia introduced an energy policy in February 1980 which established an integrated approach to approval procedures for major energy projects and removal of energy resources from the province. This booklet is a guide to the requirements of Part 2 of the *Utilities Commission Act* (R.S.B.C., 1980, C. 60) under which energy projects are reviewed and certified. It is designed to assist applicants in the application and review process for an Energy Project Certificate.

The guide is organized into three sections: the legislation and its administration, application requirements, and detailed appendices which will be useful in preparation of an application.

The information in the guide describes the energy project review process pursuant to the *Utilities Commission Act* and it is not intended to alter the Act, its regulations, or other statutes of British Columbia.



Part One: Legislation and Administration

Legislative Requirements

The *Utilities Commission Act* provides for: the regulation of public utilities, including the British Columbia Hydro and Power Authority; the review and certification of projects which generate, use, store, transport, transship, or transmit large quantities of energy; and the review and certification for the removal of energy resources from British Columbia.

The Act establishes a review process by which major energy projects obtain certification. Regulated projects, as defined under Section 16, include any large-scale project in the energy field, whether or not the proponent is a public utility normally regulated by the Commission. A regulated project must receive an Energy Project Certificate before construction, and an Energy Operation Certificate before operation. Where energy is removed from the province, an Energy Removal Certificate is required. The Act also established the British Columbia Utilities Commission as the body responsible for the regulation of public utilities.

Regulated Projects

Section 16

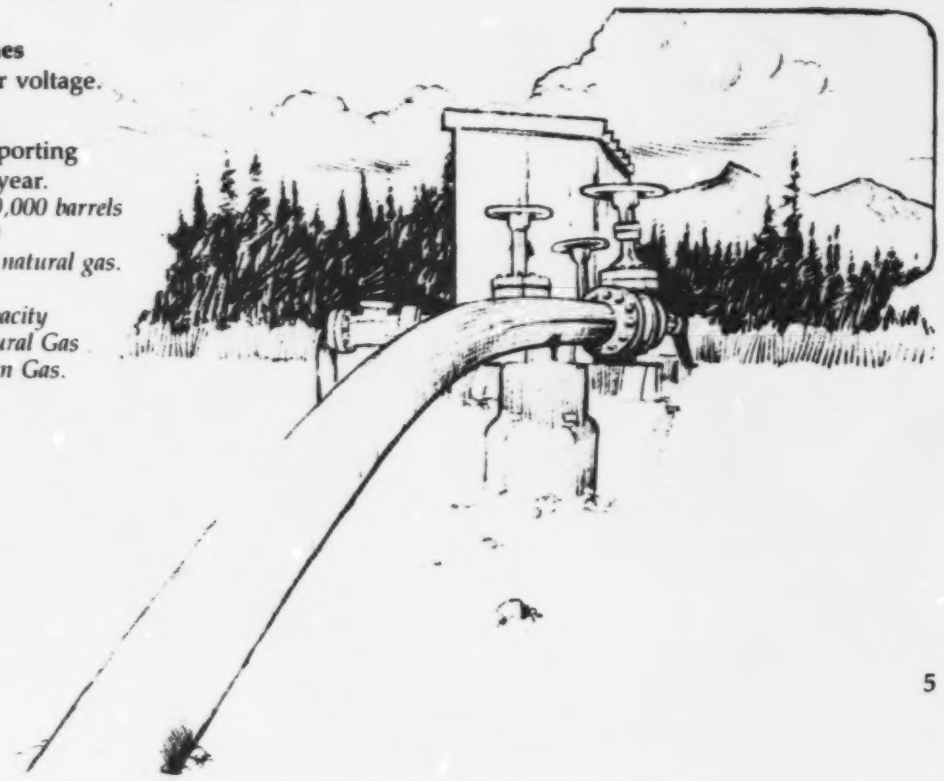
"Regulated projects" are defined according to the amount of energy used or involved in production or transmission. This includes new projects and additions to existing projects within defined limits, as follows:

Transmission Lines
- 500 kV or higher voltage.

Pipelines
- capable of transporting 16 PJ energy per year.
Equivalent to 2,570,000 barrels of crude oil or 14.9 billion cubic feet of natural gas. Existing facilities which have this capacity include Inland Natural Gas and Pacific Northern Gas.

Transshipment or Storage Facilities
- capable of storing 3PJ energy.
Equivalent to 482,000 barrels of crude oil or 2.8 billion cubic feet of natural gas.

Electricity
- a hydro or thermal power plant, or an addition to a plant, of 20 MW or higher.



Energy Use
- any new project capable of using 3PJ per year, or the addition of 3 PJ to an existing project.
Equivalent to 95 MW continuous electrical supply. Existing facilities with this capacity include Alcan Smelter (Kitimat), Cominco Smelter (Trail), MacMillan Bloedel (Powell River), Canadian Cellulose (Prince Rupert), Ocean Cement (Tilbury Island).

Other
- an undertaking of any kind that the Lieutenant Governor in Council (Cabinet) designates to be significant in the matter of energy.

Application Procedures

Section 18

An application for an Energy Project Certificate must be made to the Minister of Energy, Mines and Petroleum Resources. The application must contain the information specified in B.C. Reg. 388/80 (see Appendix One, for the full text).

Information requirements include:

- description of applicant, evidence of financial and technical capacity for undertaking the project, identification of applicant's representatives;
- description of the project and anticipated timetable;
- description of any new or expanded infrastructure made necessary by the project;
- identification and preliminary assessment of any impacts by the project on the physical, biological, and social environments, and proposals for reducing negative impacts and obtaining the maximum benefits from positive impacts;
- project justification, including technical, economic and financial feasibility studies and a benefit/cost study;
- list of approvals, permits or licences under the *Pollution Control Act* and *Water Act* and whether they are being sought as part of the application;
- list of approvals, permits or licences required under federal, provincial, and municipal jurisdictions;
- description of the applicant's public information and consultation program; and
- other information as required by the Minister, including supplementary information required to clarify the application.

Applicants seeking a Water Licence and/or Pollution Control Permit are requested to submit a Water Licence and/or Pollution Control Permit application simultaneously with the application for an Energy Project Certificate.

Review Procedures

Section 19

Once an application has been made, there are three alternative review procedures specified by the Act:

(1) the Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment, may refer the application for review by the Utilities Commission, with the ultimate decision being made by the Cabinet;

(2) the Minister of Energy, Mines and Petroleum Resources may order that an application made by a public utility be dealt with by the Commission as an application for a Certificate of Public Convenience and Necessity; or

(3) the Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment, may exempt the regulated project from the provisions of the Act.
Figure 1 outlines these procedures.

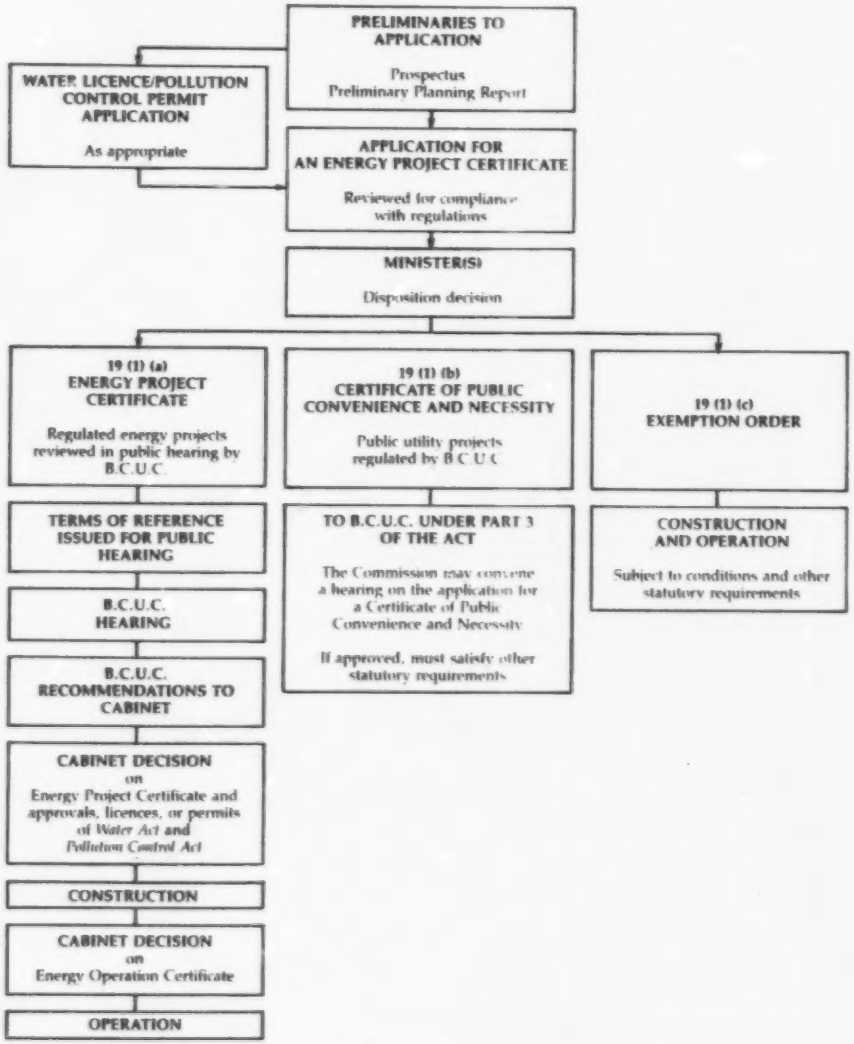
Review by Commission and Decision by Cabinet

Section 19 (1) (a)

On receipt of an application for an Energy Project Certificate, the Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment, may refer the application to the Commission for review, according to terms of reference specified by the Ministers. Depending on the project, the terms of reference may include the

Figure 1

Certification Procedures


PRELIMINARIES TO APPLICATION
Prospectus
Preliminary Planning Report
WATER LICENCE/POLLUTION CONTROL PERMIT APPLICATION
As appropriate
APPLICATION FOR AN ENERGY PROJECT CERTIFICATE
Reviewed for compliance with regulations
MINISTER(S)
Disposition decision
19 (1) (a) ENERGY PROJECT CERTIFICATE
Regulated energy projects reviewed in public hearing by B.C.U.C.
19 (1) (b) CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY
Public utility projects regulated by B.C.U.C.
19 (1) (c) EXEMPTION ORDER
TERMS OF REFERENCE ISSUED FOR PUBLIC HEARING
B.C.U.C. HEARING
B.C.U.C. RECOMMENDATIONS TO CABINET
TO B.C.U.C. UNDER PART 3 OF THE ACT
The Commission may convene a hearing on the application for a Certificate of Public Convenience and Necessity
If approved, must satisfy other statutory requirements
CONSTRUCTION AND OPERATION
Subject to conditions and other statutory requirements
CABINET DECISION
on
Energy Project Certificate and approvals, licences, or permits of Water Act and Pollution Control Act
CONSTRUCTION
CABINET DECISION
on
Energy Operation Certificate
OPERATION

requirement that the Commission recommend whether or not a Pollution Control Permit and/or Water Licence be issued.

The Commission will conduct a public hearing on the application, according to its own procedures. The Commission's report and recommendations are then submitted to the Cabinet, who may order that an Energy Project Certificate be granted, with terms and conditions, or that the application be denied. Cabinet may also order that a Pollution Control Permit and/or Water Licence be issued, and specify the necessary terms and conditions.

If an Energy Project Certificate is granted, the applicant proceeds with construction. Upon completion of construction, and before commencing operation, the applicant must demonstrate to the Cabinet compliance with the Energy Project Certificate's terms and conditions. If compliance is shown, an Energy Operation Certificate will be issued by the Cabinet. This Certificate may specify further terms and conditions.

Review and Decision by Commission

Section 19 (1) (b)

If a public utility applies for an Energy Project Certificate, the Minister of Energy, Mines and Petroleum Resources may refer the application to the Commission for a review under Part 3 of the Act.

Under Part 3, any public utility operating in the province must obtain a Certificate of Public Convenience and Necessity from the Commission. The Commission, at its discretion, may hold a public hearing on the application.

If the application is approved, the Commission will issue a Certificate of Public Convenience and Necessity, with terms and

conditions as the public convenience or necessity may require. Conditions may include matters related to construction, maintenance, rates, service etc.

Applicable statutory requirements and permitting procedures must be satisfied by the applicant.

Exemption

Section 19 (1) (c)

The Minister of Energy, Mines and Petroleum Resources, with the concurrence of the Minister of Environment, may order that the construction and operation of a project be exempt from some or all of the provisions of the Act specified in the order.

The Ministers' order may include any conditions that could be included in an Energy Project Certificate or an Energy Operation Certificate. In addition, other applicable statutory requirements and permitting procedures must be satisfied by the applicant.

Administration

An administrative framework has been developed which coordinates the agencies involved in the energy project review process (see *figure 2*). When preliminary studies or applications are submitted, they will be reviewed through this framework.

Energy Project Coordinating Committee (EPCC)

The Minister of Energy, Mines and Petroleum Resources is responsible for the administration of the *Utilities Commission Act*. The Minister of Environment's concurrence is required in the review and, in certain instances, in the disposition of an application for an Energy Project Certificate.

An Energy Project Coordinating Committee has been established to coordinate the review of regulated projects and advise the ministers at various stages of the procedures. The committee consists of three members:

- The Director of the Project Analysis Branch, Ministry of Energy, Mines and Petroleum Resources.
- The Director of the Assessment Branch, Ministry of Environment.
- A representative of the B.C. Utilities Commission staff.

Working Committees

Three Working Committees have been established to assist the EPCC, as illustrated:

- Environment/Resource/Land Use;
- Social/Economic;
- Energy/Economics/Finance.

Figure 2 identifies the Working Committees' broad areas of interest, their functions, and agency composition. Members represent agencies whose responsibilities may be affected by a regulated energy project.

Relationship to Other Project Review Procedures

Proponents will be advised at the earliest opportunity whether their project is regulated under Part 2 the Act, or whether other guideline review procedures will apply to the project.

Regulated projects will usually be reviewed through the three Working Committees. However, in the case of coal and metal mine projects subject to Part 2 of the *Utilities Commission Act*, the existing review committees under the *Guidelines for Coal Development* and *Procedures for Obtaining Approval of Metal Mine Development* will provide for the necessary review of preliminary studies. Formal contact regarding an application for an Energy Project Certificate remains with the EPCC.

Energy projects regulated under Part 2 of the Act will not normally be subject to the E.L.U.C. *Guidelines for Linear Development* or the (Draft) *Guidelines for Major Developments*. However, review procedures under these guidelines might be utilized for the development of an application, where deemed appropriate by the EPCC. Where a project is not regulated under Part 2 of the *Utilities Commission Act*, these other guidelines may be applied as a means of evaluating a project.

The requirements of the *Procurement Policy for Major Project Developments* are integrated with the energy project review process, as indicated in this guide.

Figure 2

Inter-Agency Framework

ENERGY PROJECT COORDINATING COMMITTEE

Ministry of Energy, Mines and Petroleum Resources (Project Analysis Branch)
Ministry of Environment (Assessment Branch)
British Columbia Utilities Commission (Staff Member)

WORKING COMMITTEE	ENVIRONMENT/RESOURCE/ LAND USE	SOCIAL/ECONOMIC	ENERGY/ECONOMICS/FINANCE
AREA OF GENERAL INTEREST	Resource Management Land Use Planning	Regional and Community Development Planning Social Service Policies	Energy Policy Industrial Strategy Taxation/Financial Policy
FUNCTION REGARDING APPLICATION AND PROJECT	Environmental Impact Analysis Benefit/Cost Analysis Mitigation/Compensation Permitting	Impact Analysis Social services Mitigation/Compensation Permitting	Energy Policy Demand/Supply Forecasting Economic/Financial Feasibility Benefit/Cost Analysis
MEMBER AGENCIES	Environment* Forests Agriculture and Food Transportation and Highways Lands, Parks and Housing Energy, Mines and Petroleum Resources Provincial Secretary and Government Services	Coordinated by Socio/Economic Coordinating Committee (SECC) Review Agencies Include: Municipal Affairs* Health/Education Lands, Parks and Housing Attorney General/Labour Transportation and Highways Provincial Secretary and Government Services Industry and Small Business Development	Energy, Mines and Petroleum Resources* Finance Industry and Small Business Development

**Currently chairs working committee.*

Part Two: Application Requirements

The Application Process

The legal requirements of an application for an Energy Project Certificate are identified in Regulation 388/80 of the *Utilities Commission Act* (see Appendix 1). It is important that proponents consult with the appropriate Working Committees regarding specific requirements of the Regulation and standards for an application.

The application process is organized to facilitate ongoing consultation between the proponent and government agencies in the early project planning stage. It recognizes that phasing of project planning can be important in the efficient development of an application. The proponent therefore, has the opportunity to seek considerable information, advice and response from government agencies prior to formal application. Preliminary discussions will help the proponent to define specific study requirements and methodologies and locate possible data sources. Such ongoing consultation ensures that government permit and approval requirements are identified and addressed during the planning studies and project design. Appendix 3 outlines the provincial statutes and permit requirements which may be applicable to various major regulated projects.

The general stages in the application process are outlined in Figure 3. Depending upon the project characteristics, some stages may be reduced or combined with other stages. The EPCC can provide guidance on specific requirements.

Pre-Application Phase

To facilitate the preparation and review of an application, the applicant is encouraged to prepare a prospectus and preliminary planning report prior to submitting an application. These preliminary reports help ensure that project planning will meet the requirements of the *Utilities Commission Act* and other statutes and provide the applicant with preliminary response to proposed plans. Preliminary studies and reports should be submitted to the EPCC for distribution to Working Committee representatives.

The length of the pre-application phase will depend upon the extent of project planning activities. Review time will also vary from project to project. The general objective is to coordinate agency reviews within two months of receipt of the prospectus or preliminary planning report.

The requirements outlined in the following sections will be tailored to suit particular projects.

Prospectus

The purpose of this initial report is to introduce and provide a brief description of the proposed project, its rationale and planning schedule. The prospectus initiates government review, which provides the proponent with early advice regarding application and related regulatory requirements. Upon request, a prospectus may be kept confidential, pending a proponent decision to proceed further.

The prospectus should include a concise resume of the project description, project rationale, and proposed preliminary studies.

The **Project Description** should provide a summary of project planning to date. This should include a description of proposed facilities related to the project, tentative locations under consideration, manpower estimates and approximate schedules for project planning, approval and construction.

The **Project Rationale** should outline the purpose of the project, the general implications for energy supply and demand, and the benefits to the Province of the proposed project. It should include discussion of known issues and constraints on the project.

The **Proposed Preliminary Studies** should indicate the studies and public consultation to be undertaken for the Preliminary Planning Report.

Figure 3

Energy Project Application Process

PRE-APPLICATION PHASE

PROSPECTUS

(1) General project description and schedule.
(2) Project rationale.
(3) Description of proposed preliminary studies.

Review by Energy Project Coordinating Committee and Working Committees; consultation with proponent

PRELIMINARY PLANNING REPORT

(1) Identification and assessment of feasible alternative locations.
(2) Analysis of alternative locations and identification of preferences.
(3) Preliminary Procurement Plan.
(4) Terms of reference for proposed environmental/socio-economic impact studies.
(5) Terms of reference for proposed project justification studies.
(6) Description of public consultation program.
(7) Preliminary list of approvals, licences, and permits required.

Review by Energy Project Coordinating Committee and Working Committees; consultation with proponent in developing Application

APPLICATION PHASE

APPLICATION

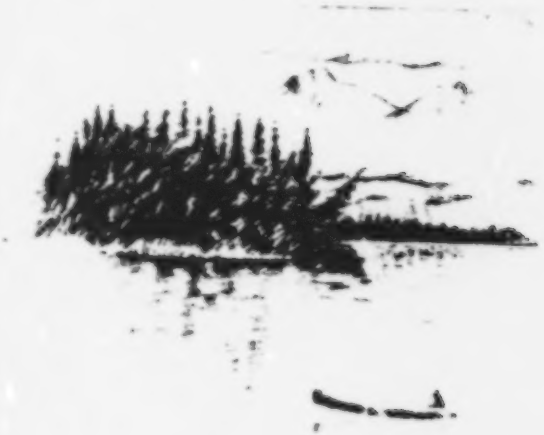
(1) Description of applicant as per Regulation.
(2) Project description:
  (a) purpose, costs, and ancillary facilities.
  (b) timetable for construction, operation, abandonment, reclamation, with critical dates.
  (c) public works, undertakings, or infrastructure entailed with costs and schedule.
(3) Environmental and socio-economic impact assessment and proposals for minimizing negative impacts and maximizing positive impacts.
(4) Project justification: energy supply/demand, technical feasibility, financial feasibility, procurement, benefit-cost data.
(5) Ancillary applications: approvals, permits, licences required under *Pollution Control Act*, *Water Act*, and other pertinent statutes.
(6) Public consultation program description and summary of response.
(7) Other information as required.

Review by Energy Project Coordinating Committee and Working Committees; consultation with applicant as necessary

APPLICATION DISPOSITION BY MINISTER(S)

[Section 19(1) of *Utilities Commission Act*]

Direct contact with technical staff of relevant ministries is encouraged where particular expertise is sought and this can be coordinated by the chairpersons of the Working Committees.



Preliminary Planning Report

The purpose of this overview document is to provide:

- **A Preliminary Environmental and Socio-Economic Assessment** of alternative locations for the project, including a general assessment of impacts associated with the preferred location(s);

- **A Preliminary Procurement Plan,** including British Columbia/Canadian procurement opportunities;

- **Detailed Terms of Reference** for project justification studies and environmental and socio-economic impact assessment required by the Regulation;

- **Description of Public Consultation Program,** underway and/or proposed; and

- **Preliminary List of Approvals, Licences and Permits** required under provincial laws.

The **Preliminary Environmental and Socio-Economic Impact Assessment** should identify and compare the alternative areas and/or corridors under consideration and select the preferred location(s). It should undertake a preliminary assessment of the preferred alternative(s) and outline proposals for detailed study of one or more of these alternatives.

This assessment should clearly set out the criteria and methodology employed in the evaluation of alternatives. It should list and assess the general environmental, social and economic impacts associated with these broad location options. The information in this preliminary assessment should be sufficient to make a comparative judgement of alternative development locations. Assessment of the preferred location(s) should include preliminary manpower plans. The preparation of this report can be assisted by the information requirements set out in Appendix 2.

The **Preliminary Procurement Plan** should include a general indication of goods and services associated with the project and procurement opportunities for British Columbian and Canadian suppliers. Specific information requirements are described in the B.C. *Procurement Policy for Major Project Developments.*

The **Terms of Reference** for studies should reflect the requirements for project justification and environmental and socio-economic impact assessment, as described further in this guide. In particular, the major assumptions and methods to be employed in these studies should be clearly identified and discussed with the various Working Committees. Review of these terms of reference will ensure that relevant studies meet the requirements of provincial government agencies and will avoid subsequent rejection.

A proponent should also indicate any required engineering field surveys, and include the scope and timing of such surveys. Conditional consent can be obtained from appropriate ministries for minimum survey works to facilitate feasibility studies and detailed planning. Such consent to survey does not imply any approval-in-principle to the project.

The **Public Consultation Program** should be described in detail, including the proposed methods, timing and public notification. It is expected that proponents will make information available to the public during the project planning stages. Once the feasible alternative(s) and the major impacts have been generally evaluated, the proponent should initiate meetings or workshops with local government authorities, local interest groups and the general public prior to preparation of an application.

The **Preliminary List of Approvals, Licences and Permits** is requested so as to provide government agencies with advance notice of approvals sought under other provincial statutes and to assist project review process.

Application

B.C. Regulation 388/80 (see Appendix 1) outlines the general content of an application for an Energy Project Certificate. The review of the application by the EPCC and the Working Committees is to ensure that the broad requirements of the Regulation are satisfactorily addressed.

The application for an Energy Project Certificate is to be an integrated statement embracing all of the aspects set out in the Regulation. The detailed assessment studies will normally be submitted as supporting documentation to the application document. The following provides elaboration of the requirements contained in the Regulation.

Applicant

B.C. Regulation 388/80 describes the specific information required about the applicant.

Project Description

The application should include a full description of the project, its purpose, capital and operating costs over time, its timetable, and the related aspects of ancillary facilities and new infrastructure, as outlined in the Regulation. The location requirements and design and operation specifications, including

waste products, for all project facilities should be included in this description. The project description should also indicate the requirements for acquisition of private and Crown land.

Environmental and Socio-Economic Impact Assessment

The environmental and socio-economic impact assessment report(s) should summarize the site/route selection, and provide a detailed description of impacts and proposals for mitigation and/or compensation. The report should:

- identify and assess the major environmental and socio-economic impacts associated with each alternative site or route; and undertake a comparison and selection of a preferred alternative on the basis of technical engineering, environmental, socio-economic and cost criteria (contained in preliminary planning report);
- identify and assess in detail the environmental, social and economic impacts associated with the preferred location(s) and present the proposals for reducing negative impacts and obtaining the maximum benefits from positive impacts;
- outline the plans and procedures for site specific impact mitigation and/or compensation and their implementation;
- outline the plans and procedures for field inspection and monitoring programs for ensuring compliance and management of impacts; and
- outline the plans and procedures for clean-up, revegetation, reclamation and abandonment of the project or ancillary facilities, as applicable.

Specific information requirements on environmental and socio-economic impacts can be developed with reference from the appended biophysical and land use information, the socio-economic information, and consultation with the Working Committees. The principles of the *Environmental and Social Impact Compensation/Mitigation Guidelines* (ELUC Secretariat, 1980) provide further direction in preparation of the application.

Many of the project design details and mitigation/compensation proposals may still require further development, in consultation with various agencies or groups throughout the review and certification phases. Final plans therefore, need not necessarily be complete by the application stage, but should address the general requirements outlined above. The proposed procedures for completing mitigation and compensation plans should be specified.

Project Justification

Studies on project justification should be guided by the terms of reference prepared in consultation with the Energy/Economics/Finance Working Committee. The purpose of this assessment is to provide the EPCC with sufficient information on the economic and financial viability of the project, the overall benefits and costs to the Province, and the potential effects upon energy resources and energy use.

The scope of information requirements within this section may vary, depending upon the size and nature of the regulated project and the potential for externalities and government subsidies. Specific requirements therefore, may be established to suit project characteristics such as the public utility or private investment related to an application. In general, and subject to consultation with the Working Committee, project justification should address:

- energy supply and demand forecasts;
- technical feasibility information related to project justification;
- financial feasibility information on both financial arrangements and evidence of commercial viability;
- procurement plan of B.C./Canada content goals;
- economic information on all project benefits and costs and their distribution, including non-quantifiable benefits and costs.

Appendix 2 details the type of information required for the above assessment.

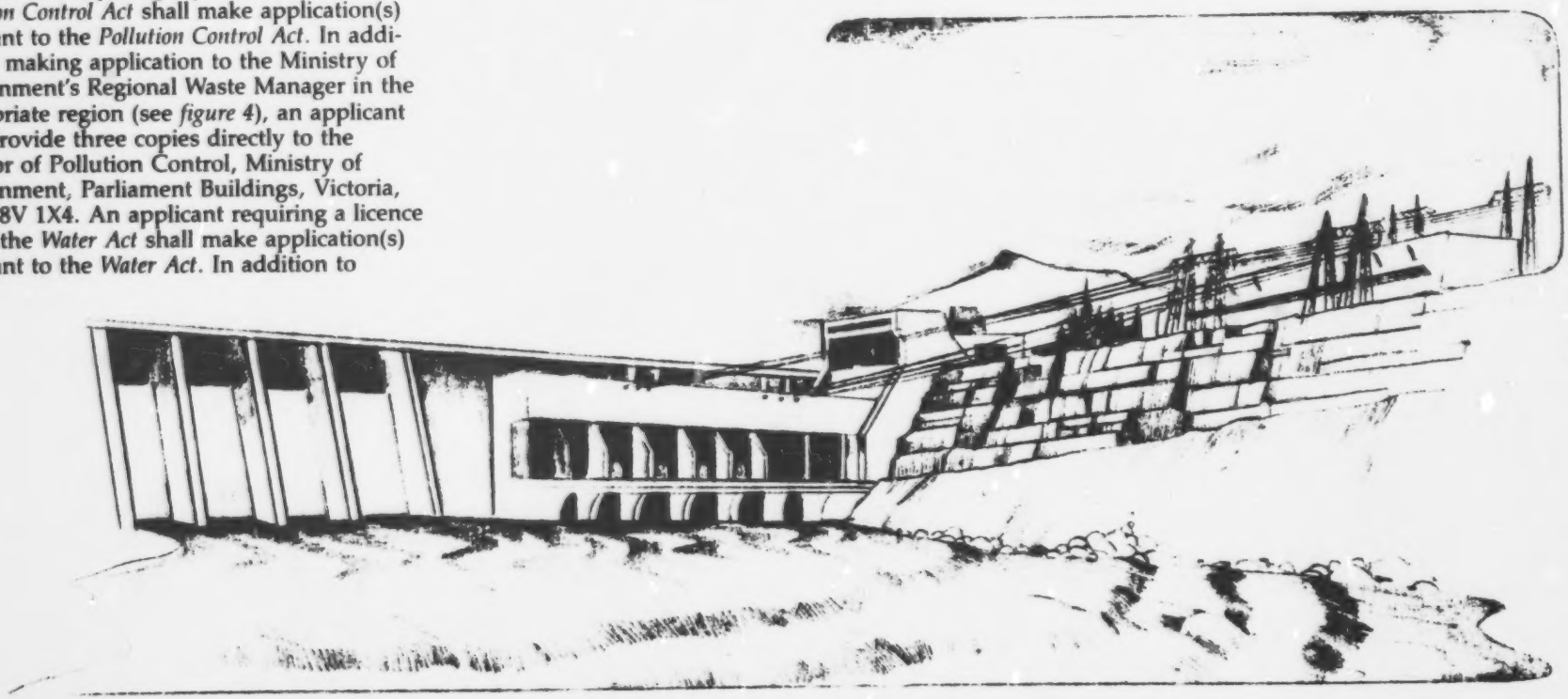
Ancillary Applications

An application must contain a list of approvals, permits or licences required under the *Pollution Control Act*, the *Water Act* and all other federal, provincial and municipal statutes. Applicants should include as much information as possible on the proposed activity that requres an approval, permit or licence.

All application(s) for permits and licences pursuant to the *Pollution Control Act* and/or *Water Act* should be made simultaneously with the submission of an application for an Energy Project Certificate, to ensure coordination of public hearing and approval requirements. An applicant requiring a permit under the *Pollution Control Act* shall make application(s) pursuant to the *Pollution Control Act*. In addition to making application to the Ministry of Environment's Regional Waste Manager in the appropriate region (see *figure 4*), an applicant shall provide three copies directly to the Director of Pollution Control, Ministry of Environment, Parliament Buildings, Victoria, B.C. V8V 1X4. An applicant requiring a licence under the *Water Act* shall make application(s) pursuant to the *Water Act*. In addition to making application via the Water Recorder in the appropriate Water District, an applicant shall provide three copies directly to the Comptroller of Water Rights, Ministry of Environment, Parliament Buildings, Victoria, B.C. V8V 1X4.

Applicants may be requested, in certain circumstances, to also apply for approvals (either issued in lieu of a permit or licence where action does not exceed six months or issued to authorize the construction of works in and about a stream) under the *Pollution Control Act* or *Water Act*, simultaneously with an application for an Energy Project Certificate. This is to ensure that significant issues related to these statutes are addressed concurrently with the energy project review process.

It is the responsibility of each applicant to ensure compliance with all federal, provincial and municipal enactments. Appendix 3 contains a list of the major provincial statutes, which could have application, but this list is not exhaustive. Accordingly, it is the responsibility of each applicant to ensure that all other requirements relative to an energy project are satisfied. Permits, licences and approvals under other provincial statutes may be applied for at times considered appropriate by the relevant agencies.



Public Consultation

An application must contain a description of the applicant's public information and consultation program. This should include a report on public notices, meetings and workshops, and other public consultation. It should contain a summary of information dissemination, public responses, major issues and concerns, and potential resolution of such issues and concerns.

Other Information

Other information may be requested by the Minister of Energy, Mines and Petroleum Resources, including supplementary information to clarify information contained in the application.

If an applicant wishes to submit certain information supporting an application with the request that it be treated confidentially, such information shall be delivered under separate cover together with an explanation of reasons for the request and the period during which confidentiality should endure. If the Minister of Energy, Mines and Petroleum Resources declines to accept the request for confidentiality, the information and all copies thereof shall be returned to the applicant.

Figure 4

RESOURCE MANAGEMENT REGIONS

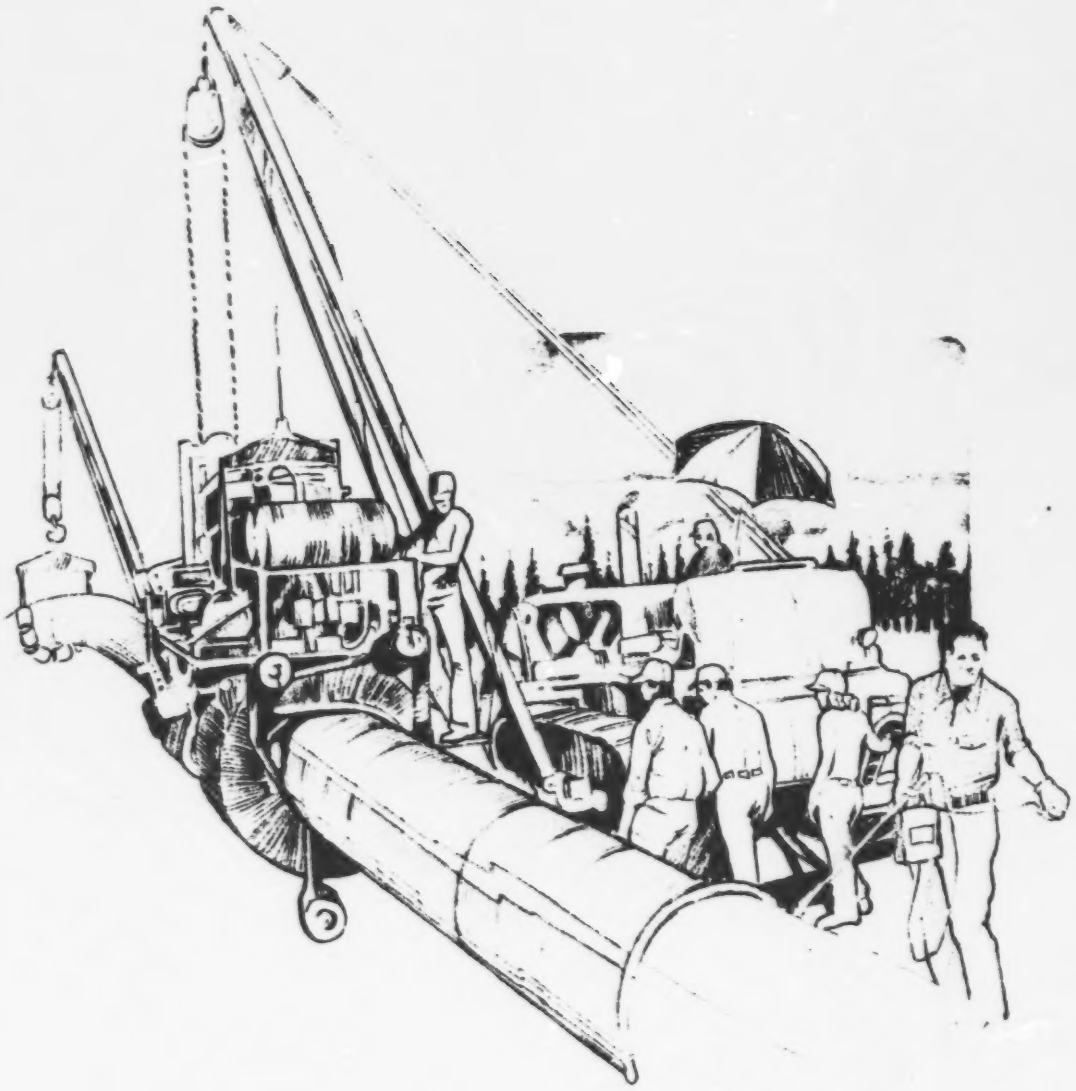
Submission of Application

An application under Section 18 of the Act must contain the information required by Regulation 388/80 and be presented in the format prescribed. The facts therein shall be supported by affidavit. An original, signed application, accompanied by supporting material and studies shall be delivered to the Minister of Energy, Mines and Petroleum Resources, Parliament Buildings, Victoria, B.C. V8V 1X4. Forty copies of the application documents shall also be forwarded to the Director, Project Analysis Branch, Energy Resources Division. Additional copies of an application may be requested by the Minister.

Disposition of Application

An applicant will be notified as to the disposition of an application pursuant to Section 19 of the Act. (The Ministry of Energy, Mines & Petroleum Resources will normally issue press releases upon disposition of an application, issuance of public hearing terms of reference and upon certification decisions.) An applicant can expect that the application and supporting material will be made public after the Minister of Energy, Mines and Petroleum Resources announces, with the concurrence of the Minister of Environment, the disposition of the application pursuant to Section 19.

Inquiries regarding the submission of an application should be directed to: Director, Project Analysis Branch, Ministry of Energy, Mines and Petroleum Resources, Parliament Buildings, Victoria, B.C. V8V 1X4.



Appendices

Appendix 1: Utilities Commission Act, Part 2; B.C. Regulation 388/80

Utilities Commission Act
Part 2

Interpretation

16. In this Part

"energy"
includes every form of energy;

"energy operation certificate"
means a certificate issued by the Lieutenant Governor in Council under this Act, authorizing the holder of the certificate to operate a regulated project;

"energy project certificate"
means a certificate issued by the Lieutenant Governor in Council under this Act, authorizing the holder of the certificate to construct a regulated project;

"energy resource"
means natural gas and oil, and all other forms of petroleum and hydrocarbon, in gaseous or liquid state, and electricity;

"energy transhipment terminal" or *"energy storage facility"*
means a place where an energy resource is accumulated or stored in bulk as part of the process of being transported or distributed;

"energy use project"
means a mill, factory, plant, smelter, oil refinery, metal refinery or other undertaking or facility designed to use, convert or process an energy resource or coal, or any combination of them, at the rate of 3 PJ or more a year, and for the purpose of this definition an energy resource other than electricity is used, converted or processed at that rate where it is of a quantity capable of yielding that amoung of energy by combustion;

"hydroelectric power plant"
means a facility for the generation of electricity, from the motion of water, or the position or potential motion of water, and includes associated dams, diversion works, water conduits and all structures, machinery, appliances, fixtures and equipment;

"regulated project"
means

(a) an electric transmission line of 500 kV or higher voltage,

(b) an energy transhipment terminal or energy storage facility, capable of storing an energy resource in a quantity that is capable of yielding by combustion 3 PJ of energy,

(c) an energy use project,

(d) a transmission pipeline, capable of transporting in one year natural gas, oil or solids, or a liquid or gas derived from them, in a quantity that is capable of yielding by combustion 16 PJ of energy,

(e) a hydroelectric power plant that has a capacity of 20 MW or more of electricity,

(f) a thermal electric power plant that has a capacity of 20 MW or more of electricity,

(g) an addition by which 20 MW or more of electric capacity will be added to a hydroelectric or thermal electric power plant,

(h) an addition to a regulated project, referred to in paragraphs (a) to (d), that would if constructed alone fall within the definition of "regulated project", and

(i) an undertaking of any kind that the Lieutenant Governor in Council designates to be significant in the matter of energy;

but "regulated project" does not include

(j) a project that is complete or in operation before this Act comes into force, or

(k) a project in respect of which,

before this Act comes into force, site preparation or the fabrication, construction, installation or supply of buildings, equipment, machinery or other facilities has begun;

"review"
means a review under section 20;

"thermal electric power plant"
means a facility for the generation of electricity from the combustion of natural gas, oil, petroleum products, coal, wood or plant products or from the use of geothermal energy, and includes all associated structures, machinery, appliances, fixtures and equipment, and storage and handling facilities;

"transmission pipeline"
means a pipe or system of pipes through which natural gas, oil, solids, or a liquid or gas derived from natural gas, oil or solids, whether in suspension or other form is transported and includes compressor or pumping facilities and other equipment related to the operation of the transmission pipeline, associated terminal or storage facilities, but does not include
(a) flow lines from wells,
(b) secondary lines for gathering that are located within a producing area, or
(c) distribution lines that deliver to ultimate consumers.

Energy project and operation certificates

17. (1) No person shall, except to the extent that he is authorized to do so under section 19, construct or operate a regulated project except in accordance with an energy project certificate or energy operation certificate.

(2) Where a person contravenes subsection (1), the construction or operation may be restrained in a proceeding brought by the minister in the Supreme Court.

(3) The making of an order under subsection (2) does not prevent the imposition of a penalty under section 124.

Application for certificate

18. An application for an energy project certificate or for modification of it or of an energy operation certificate shall be made to the minister and shall contain information the minister prescribes.

Minister's disposition of application

19. (1) On receipt of an application under section 18 the minister may
(a) with the concurrence of the Minister of Environment, refer the application to the commission for a review,
(b) order, in a case where the application is made by a public utility, that the application be dealt with by the commission under Part 3 as an application for a certificate of public convenience and necessity, or
(c) with the concurrence of the Minister of Environment, order that the construction and operation of the regulated project is exempt from provisions of this Act specified in the order.

(2) Where the minister refers an application to the commission, he may designate a commissioner or temporary commissioner to act as chairman for the purpose of the review.

(3) An order under subsection (1) (c) may include any conditions that could be included in an energy project certificate or energy operation certificate under section 21 (1) (b), and a person constructing or operating the project is bound by them in the same way as if they had been included in an energy project certificate or energy operation certificate issued to him, and sections 17 and 124 apply.

Review by commission

20. (1) Where an application for an energy project certificate is referred to the commission for a review, the commission shall, subject to subsection (3), hear the application in public hearing in accordance with terms of reference specified jointly by the Minister of Energy, Mines and Petroleum Resources and the Minister of Environment, and on conclusion of the hearing shall submit a report and recommendations to the Lieutenant Governor in Council.

(2) The terms of reference may include a requirement that the commission consider and recommend whether an approval, licence or permit or an amendment to any of them should be made, given or issued under section 4, 5, 7, 8, 9 or 10 (4) of the *Pollution Control Act* or section 6, 7, 10 or 11 of the *Water Act*.

(3) The commission may, for the purpose of receiving information or evidence that the commission considers is of a confidential character, exclude the public from the hearing while it receives that information or evidence.

Disposition of application by Lieutenant Governor in Council

21. (1) On receiving the report and recommendations of the commission the Lieutenant Governor in Council may order
(a) that the energy project certificate applied for be refused,
(b) that the energy project certificate applied for be issued subject to

conditions he considers to be in the public interest, and the conditions may include

(i) a requirement that natural gas used by or in connection with the construction and operation of the project be supplied only under a contract which

(A) includes as parties the British Columbia Petroleum Corporation and the operator of the project, and

(B) includes terms specified by the Lieutenant Governor in Council, and

(ii) other conditions that the Lieutenant Governor in Council considers necessary to be included in an energy operation certificate for the project,

(c) that an approval, licence or permit or an amendment to any of them referred to in section 20 (2) be made, given or issued, subject to any terms or conditions the Lieutenant Governor in Council specifies,

and the order is final and binding.

(2) Where the Lieutenant Governor in Council gives a direction referred to in subsection (1) (c), the person, board, tribunal or agency that has, apart from this Act, the authority or power to issue or decide to make, give or issue the approval, licence or permit or amendment shall, notwithstanding anything in the *Pollution Control Act* or the *Water Act*, make, give or issue it in accordance with the direction, and the making, giving or issuance is final and not subject to any review or appeal under those Acts.

(3) On completion of the construction of a regulated project for which an energy project certificate was issued, the Lieutenant Governor in Council shall, on being satisfied that the conditions of the energy project certificate have been substantially complied with, issue an energy operation certificate for the regulated project, and may include in the energy operation certificate the conditions referred to in subsection (1) (b) (i) and (ii).

(4) Where a requirement referred to in subsection (1) (b) (i) is included in an energy project certificate or energy operation certificate,

(a) sections 44, 45, 64, 65, 66, 68, 69, 70 and 71 shall, with respect to the natural gas supplied under the required contract, operate to regulate only the part of the price to be paid for the natural gas by the certificate holder that consists of transportation costs and charges, and

(b) the revenue received by the British Columbia Petroleum Corporation or a public utility in respect of the sale of the natural gas to the holder of the certificate pursuant to the required contract shall not be subject to any levy or other payment pursuant to any agreement made by the municipality before or after this section comes into force under section 646 or 647 of the *Municipal Act*.

(5) No approval, licence or permit or amendment to any of them given, issued or made under subsection (2), shall be varied without the approval of the Lieutenant Governor in Council.

B.C. Reg. 388/80

Filed September 16, 1980

Schedule

Application Requirements Under Section 18 of the Utilities Commission Act

1. An application under section 18 shall contain the following information:

(1) Application for an Energy Project Certificate

(a) Applicant

(i) the name, address and nature of business of the applicant and all other persons having a direct interest in the ownership or management of the project;

(ii) evidence of the financial and technical capacity of the applicant and other persons involved, if any, to undertake the project;

(iii) the name, title and address of the person with whom communication should be made respecting the application;

(iv) the name and address of legal counsel for the applicant, if any;

(b) Project Description

(i) a description of the project, its purpose and cost, including all ancillary or related facilities that are proposed to be constructed, owned or operated by the applicant;

(ii) an outline of the anticipated timetable for construction, operation, abandonment and reclamation, as applicable, together with dates by which critical events must take place to ensure continued economic viability;

(iii) a description of any new or expanded public works, undertakings or infra-structure that will be entailed by the project, together with an estimate of the costs and necessary completion dates;

(iv) identification and preliminary assessment of any impacts by the project on the physical, biological and social environments; and proposals for reducing negative impacts and obtaining the maximum benefits from positive impacts;

(c) Project Justification

(i) studies of the technical, economic and financial feasibility of the project, identifying assumptions and sources of data;

(ii) a study estimating the value of all the project's costs and benefits and their distribution or, where not quantifiable, identifying the cost or benefit and stating that it cannot be quantified;

(d) Ancillary Applications

(i) a list of approvals, permits or licences required under the *Pollution Control Act* and *Water Act*, and whether they are being sought as part of the present application;

(ii) a list of other approvals, permits or licences required under federal, provincial and municipal law;

(e) General

(i) a description of the applicant's public information and consultation program;

(ii) other information as required by the minister, including supplementary information to clarify information contained in the application;

(2) Application for Modification to an Energy Project Certificate or Energy Operation Certificate

(a) the name, address and nature of business of any person who has a direct interest in the ownership or management of the project and who did not have an interest at the time of the previous application;

(b) a description of the proposed modification and explanation of its purpose;

(c) an assessment of the effects of the proposed modification in relation to the information and analyses contained in the original application;

(d) other information with, or to supplement, the application as required by the minister, including supplementary information to clarify information contained in the application;

(e) a copy of the existing Energy Project Certificate or Energy Operation Certificate

Appendix 2: Information Requirements

1. **Project Justification**
2. **Site and Route Selection Process**
3. **Biophysical and Land Use Information**
4. **Socio-Economic Information**

Introduction

The following information requirements provide guidance on the methodology and the general type of information to be addressed in an application for an Energy Project Certificate. Information in these categories assist both the proponent and government in the development of an acceptable project design and in the management of project impacts. Since projects vary in nature and severity of impacts, the specific terms of reference for studies should be prepared in consultation with the Working Committees.

Section 1 below provides detail on the type of information required for project justification studies. Some overlap exists with socio-economic impact information, but this does not imply duplication of studies.

Section 2 outlines the general procedures for location of an optimum site/route. The particular steps and level of assessment can be adjusted, in consultation with EPCC and Working Committees, to suit project design and circumstances.

Section 3 and 4 describe the types of information related to the inventory, assessment, mitigation and compensation of biophysical, land use and socio-economic impacts. The relevance of each component to an individual project must be determined in consultation with the Working Committees and with appropriate government agencies. Specific requirements will vary depending upon project characteristics.

1. Project Justification

1.1 Supply/Demand Forecasts

In order to demonstrate the need for energy provided by the project, and/or the availability of energy for the project, relevant forecasts of energy demand and supply are to be provided. These forecasts should be fully documented as to data use, assumptions, methodology and supporting rationale.

The data requirements may be limited to forecasts for the project; in other cases they may encompass regional or provincial forecasts, where a project has broad implications for energy supply and demand. The scope of this forecast data will be determined by project characteristics and will be specified in discussions with the Working Committees.

1.2 Other Technical Data

Other relevant energy information related to the technical feasibility of a proposed project should be included where it bears upon project justification. This may include aspects of system engineering, efficiency, and security of supply benefits and other public interest matters.

1.3 Financial Feasibility

In order to assess the commercial viability of a project and the potential risks for public investment, subsidy, infrastructure or services, the applicant should submit relevant financial information. The information should normally provide:

(a) a description of financial arrangements, including sources of financing and debt/equity ratio;

(b) a description and evidence of commercial viability, including sensitivity to changes in major cost items and market fluctuations; this may include discounted cash flow return on investment, where appropriate.

1.4 Procurement

The assessment of economic effects of a project should include a procurement plan, indicating goals for British Columbian and Canadian content and the plan for evaluating progress toward meeting these goals. Applicants should refer to the *Procurement Policy for Major Project Developments*.

1.5 Benefits and Costs

Taking into account the preceding information, an application should provide as per Regulation 388/80: "a study estimating the value of all of the project's costs and benefits and their distribution or, where not quantifiable, identifying the cost or benefit and stating that it cannot be quantified". In some cases this study may be limited to a summary of major costs and benefits. In other cases, where determined necessary by the EPCC and the Working Committees, it may encompass a full accounting of all costs and benefits. It should normally employ the principles set out in the *Guidelines for Benefit-Cost Analysis* and state other assumptions and methods, including sensitivity analysis agreed upon with the Working Committees.

The study should include the following:

(a) capital and operating costs over time;

(b) estimates of government taxes and royalties at the local, provincial and federal levels;

(c) estimates of government costs or subsidies, including infrastructure and services;

(d) estimates of total direct labour income during construction and operation;

(e) summary of all quantifiable direct benefits and costs to B.C. residents and their distribution;

(f) summary of all non-quantifiable direct benefits and costs to the residents of B.C., and their distribution; and

(g) where appropriate, the net present value of the project, and sensitivity to changes in major cost items and variations in the discount rate.

2. Site and Route Selection Process

To minimize adverse impacts and maximize beneficial impacts, as indicated by the Regulation, the proponent should ensure that an optimum location is proposed. It is standard practice that environmental and socio-economic impact assessments provide sufficient justification for the proposed location of a project. In some cases, project location is strictly dependent upon energy resource, infrastructure or other parameters and few or no alternative location will exist. In other cases, considerable flexibility will exist in selecting as site or route location. The extent of analysis, therefore, can be adjusted accordingly.

The following steps briefly outline the general information and procedures for the selection of a site or route. This should achieve the best balance between low impact on the quality of the environment and interference with or dislocation of human activities, and total cost of the project. The approach suggests a phased examination of a **broad study region**, the **area or corridor options** within this region, and the subsequent **site or route options**.[1]

Field inventory work should accord with the data collection and classification procedures recommended by provincial agencies.[2]

2.1 Define Study Region

The boundaries of an initial study region are delineated based upon reasonable judgement. This should include a brief rationale as to how these were defined (e.g. energy source, markets, major physical barriers, distance constraints).

2.2 Identify Location Alternatives

The feasible alternatives within this region are identified on the basis of: (a) technical engineering requirements and constraints, (b) environmental (biophysical and land use) constraints, and (c) socio-economic constraints. The regional limitations to location become apparent through an overview description of major resource and land uses and capabilities, social and community characteristics and the technical, system and engineering constraints. The process for proposing alternative locations should be clearly documented.

2.3 Assess and Compare Location Alternatives

Each of the alternative locations is then assessed on the basis of: (a) technical/engineering difficulty, (b) environmental features and impacts, (c) socio-economic features and impacts, and (d) cost estimates. This overview inventory and assessment is normally undertaken at a reconnaissance level, providing sufficient data upon which to compare the broad alternatives.

The area or corridor alternatives are compared using the above preliminary assessment data. The proponent may wish to simply rank alternatives, as a basis for seeking government and public feedback in selecting a preferred alternative. In some cases, it may not be possible to select a preferred alternative, in which case, more than one option can be assessed at the following detailed level.

This step should therefore, identify and provide a preliminary assessment of the preferred location alternative(s). A preliminary planning report is then submitted for review and comment, prior to preparation of an application.

1. A corridor is defined as a linear strip of land of varying width within which it is possible to locate at least one feasible route. A route may contain one or more feasible rights-of-way.
2. For example: *Describing Ecosystems in the Field*, Ministry of Environment/Ministry of Forests, 1980; *Aquatic System Inventory and Analysis*, Ministry of Environment, 1977; *Terrain Classification System*, Ministry of Environment, 1976; *Laboratory Manual for the Chemical Analysis of Waters, Wastewaters, Sediment and Biological Tissues*, Ministry of Environment, 1976.

2.4 Assess Preferred Location(s)

A detailed study is undertaken on the preferred area or corridor. This includes an examination of the alternative sites or routes within an area(s) or corridor(s). On the basis of this detailed inventory and assessment, and employing similar criteria as above, the preferred site or route and the related biophysical and socio-economic impacts should be identified.

2.5 Identifying Mitigation and Compensation Proposals

The site specific mitigation measures or plans should be described in as much detail as possible. This includes those measures to be implemented before, during or after construction.

The unavoidable and residual impacts should also be described, along with proposals to compensate for such impacts. While it may not be possible to finalize compensation proposals at this stage, the general principles should be outlined.

2.6 Identify Implementation Proposals

The procedures for ensuring that design plans and mitigation and compensation proposals are implemented should be described. This should include details on the preparation of clearing and construction contracts, field procedures manuals, field inspection and reporting arrangements, and impact monitoring undertakings.

3. Biophysical and Land Use Information

Studies for the assessment of impacts may include the following categories. Appropriate areas of investigation, inventory scale, study methodology and timetable, and related parameters should be developed in cooperation with Working Committees.

3.1 Climate and Air Quality
- Temperature, inversions, precipitation, winds
- Air quality

3.2 Terrain
- Surficial and bedrock geology
- Soils
- Slope stability and erosion potential
- Permafrost

3.3 Vegetation
- Vegetation types
- Rare and endangered plants
- Revegetation potential

3.4 Agriculture
- Soils and drainage
- Agricultural capability
- Forage and horticultural crops
- Livestock management
- Irrigation practices and future requirements

3.5 Forest Resources
- Stand type
- Age class
- Site class
- Operability
- Industrial profile

3.6 Mineral and Petroleum Resources
- Coal and mineral potential, and occurrences
- Petroleum and natural gas resources
- Aggregate supplies and quarries

3.7 Water Resources
- Drainage, including proposed dams, water diversion, stream disturbance
- Water quantity (surface and groundwater), including hydrologic regime data and water withdrawals
- Water quality (surface and groundwater), including waste discharge and suspended sediments
- Community watersheds and other water uses.

3.8 Aquatic and Marine Resources
- Benthic and planktonic fauna/flora
- Fish populations and capability
- Sensitive species, periods and habitat
- Fishing activity and management
- Shellfish and marine plant industry
- Fish processing industry

3.9 Wildlife Resources
- Wildlife populations and capability
- Sensitive species, periods and habitat
- Hunting activity and management
- Guiding and trapping

3.10 Recreation and Visual Resources
- Outdoor recreation capability
- Recreational use
- Provincial and regional parks, and reserves
- Scenic values

3.11 Heritage Resources
- Sites and objects of historical, architectural, archaeological, paleontological and scenic significance

3.12 Environmental Hazards
- Known and potential occurrence of hazards such as snow avalanches, landslides, mudflows, windstorms, earthquakes, tidal waves, floods and fire hazards

3.13 Land Tenure, Status and Use
- Private land
- Crown land, ecological reserves, forest reserves, and other reserves and easements
- Indian Reserves and lease arrangements
- Agricultural Land Reserves
- Grazing leases and permits
- Coal, mineral, petroleum, and aggregate reserves and leases
- Status of plans, zoning (local government, provincial agencies)
- Land use and access.

3.14 Noise
- Decibel levels at various distances from sources

3.15 Fuels and Hazardous Materials
- Storage, handling and safety measures
- Contingency plans for the containment and clean-up of spills of fuel and toxic or other hazardous material.

3.16 Waste Management
- Discharges of gaseous, aqueous and solid wastes
- Measures to control and/or manage wastes and effects on the receiving environment.

4. Socio-Economic Information

Studies for the assessment of impacts may include the following categories. Appropriate areas of investigation, inventory scale, scale, study methodology and timetable and related parameters should be developed in cooperation with Working Committees of relevant individual agencies.

4.1 Manpower
- Manpower requirements, timing and delivery mechanisms for construction phase;
- Operational manpower requirements and manpower plan (e.g. timing, training and sources of supply;
- Projected impacts on regional and provincial labour markets;
- Occupational health and safety during construction and operation;

4.2 Income
- Total direct labour income during construction and operation;
- Impact on wage levels;
- Total government revenue: regional, provincial, federal;

4.3 Population
- Existing population total, distribution and demographic characteristics;
- Projected population totals, distribution and demographic characteristics during construction phase and operation phase;

4.4 Human Services Impact
- Projected demand for, and impact on, the facilities and programs for each general service category:
  - Education services;
  - Recreation services;
  - Health care services;
  - Social services;
  - Communication services;
  - Court and judicial services;
  - Fire and police protection services;

4.5 Social Impact
- Social stability and adaptability of affected community groups;
- Cultural services (e.g. theatres, etc.);
- Social problems and social costs;
- Occupational health impacts;
- Community integration;
- Relocation of residents;

4.6 Economic Impact
- Economic impact benefits and costs as indicated in project justification information (Appendix 2, Section 1);

4.7 Community Impact
- Housing (housing demand and supply issues during construction and operating phases including capacity of housing market, affordability and company's housing policy);
- Community land (requirements for land for residential, commercial, industrial, institutional and other uses);
- Community infrastructure (demand and supply for sewage system, water system and other infrastructure);

4.8 Local Government Impact
- Impact on local government plans, finances and organization (e.g. boundaries, corporate status) and capacity to respond to impact for all local governments and Indian Bands likely to be affected by the development;

4.9 Regional Impacts
- Impact on existing transportation network and projected demand for expansion of new services;
- Impact on existing public utilities and projected demand for expansion of new services.

Appendix 3: Provincial Statutes

Which May be Applicable to Energy Projects

Introduction

It is the responsibility of each applicant to ensure compliance with all relevant enactments, including federal, provincial and municipal requirements. This appendix contains a list of the major provincial statutes which may be applicable, but this is not exhaustive. Accordingly, it is the responsibility of each applicant to ensure that all other requirements relative to an energy project are satisfied.

STATUTE	APPROVALS	AGENCY
Agricultural Land Commission Act	Permission to use land in an agricultural land reserve for a purpose other than farm use. Compliance with *Guidelines for Linear Development on Agricultural Land*.	Agricultural Land Commission; Ministry of Agriculture & Food
Boiler and Pressure Vessel Act	Approval of all boiler, pressure vessels & refrigeration plants.	Safety Engineering Division, Ministry of Labour
Coal Mine Regulation Act	Approval of mine plan by Chief Inspector, including work system and support system approval; Stability approval for tailings impoundments; Reclamation permit authorizing commencement or continuance of work in accordance with approved program for reclamation and conservation.	Inspection and Engineering Branch, Ministry Energy Mines and Petroleum Resources
Commercial Transport Act	Registration and licensing of commercial vehicles; Regulations and permits respecting commercial vehicle operation and weight.	Weigh-Master, Motor Vehicle Branch, Ministry of Transportation & Highways.
Environment Management Act	Requirement for impact assessment, environmental protection order, as required.	Assessment Branch, Ministry of Environment

STATUTE	APPROVALS	AGENCY
Fire Services Act	Regulations for the storage, handling and use of flammable and combustible liquids; Permit system in connection with the storage or flammable and combustible liquids.	Local Fire Commissioner, Ministry of Attorney General
Fisheries Act (B.C.)	Requirements for designated rivers, streams or waterways regarding the provision of fish protective devices on dam or hydraulic projects; Approval of plans affecting the passage of fish.	Fish & Wildlife Branch, Ministry of Environment
Fisheries Act (Canada)	The *Fisheries Act* contains requirements regarding the construction of fishways or canals, the provision of fishstops or diverters and the flow of water and, also, pollution control provisions regarding the deposit of deleterious substances in water. Provincial conservation officers, where designated fisheries officers, are also charged with enforcement of the federal *Fisheries Act*.	Fish & Wildlife Branch, Ministry of Environment
Forest Act	Permission to use provincial forest for other than the enumerated purposes; Licence or permit for cutting timber; Permit for the use of fire.	Ministry of Forests
Gas Act	Approval of installation or alteration of gas piping, appliance or vent in any premises.	Safety Engineering Division, Ministry of Labour
Gas Utility Act	"Gas utility" subject to regulation under the *Utilities Commission Act*, including requirements regarding regulated projects involving the storage, use and transmission of gas.	B.C. Utilities Commission
Health Act	Approval of construction camp operations. Regulations for the sanitary control of industry camps.	Public Health Inspector, Ministry of Health
Heritage Conservation Act	Permit to excavate or alter a provincial heritage site and to remove, move or alter heritage objects from it, must be obtained.	Heritage Conservation Branch, Ministry of Provincial Secretary & Government Services
Highway Act	Approval of plans affecting designated highways and access to highways, including setback and sight clearance restrictions.	Regional Approving Officer, Ministry of Transportation & Highways

STATUTE	APPROVALS	AGENCY
Highway (Industrial) Act	Restrictions regarding the construction, location and operation of industrial roads, including the requirement of approval to cross or join a public road or highway.	Highways Branch, Ministry of Transportation & Highways
Land Act	Requirements regarding the disposition of Crown land, including sales, leases, licences of occupation, rights-of-way, easements and leases or other dispositions of building or construction materials; Permission to construct upon Crown land, including access roads; Gravel removal order.	Lands and Housing Regional Operations, Ministry of Lands, Parks & Housing.
Mining Regulation Act	Approval of mine plane by Chief Inspector, including approval of the filed plan of the system to work the mine; Stability approval for tailings impoundments; Reclamation permit authorizing commencement or continuance of work in accordance with approved program for reclamation and conservation.	Inspection and Engineering Division, Ministry of Energy, Mines & Petroleum Resources.
Municipal Act	By-law within municipal and regional district boundaries.	Municipal Councils, Regional District Boards.
National Energy Board Act (Canada), Gas Pipeline Regulations, Regulation 27	Provides that a company shall not permit liquid or solid wastes to be deposited upon the ground or into bodies of surface water contrary to any enactment of a province or any regulations made pursuant thereto.	Waste Management Branch, Ministry of Environment
Petroleum & Natural Gas Act	Geophysical licence for exploration; Natural gas licence upon discovery, Petroleum/natural gas lease for production, well/test hole authorization, drilling reservation, rig licence; Certificate of Restoration.	Petroleum Resources Division, Ministry of Energy, Mines & Petroleum Resources.
Park Act	Park use permit or resource use permit in recreation area necessary in order to carry out certain activities including industrial or commercial activities.	Parks & Outdoor Recreation Division, Ministry of Lands, Parks & Housing.

STATUTE	APPROVALS	AGENCY
Pesticide Control Act	Permit from Pesticide Control Branch for the use of pesticides.	Pesticide Control Branch, Ministry of Environment
Pipeline Act, Railway Act	Approval of high pressure pipelines; Approval to cross highway, private road, railway, irrigation ditch, drain, telegraph, telephone or electric power line or pipeline; Other restrictions regarding alterations, spillage; Compliance with Canadian Standards Association Code.	Engineering & Inspection Division, Ministry of Transportation & Highways.
Pollution Control Act, Litter Act	Permit or temporary approval from the Director of Pollution Control for the discharge or emission of effluent, waste material, contaminants on land, into water or into the air; Restrictions regarding the discharge or disposal of litter, sewage or waste on land or into water.	Waste Management Branch, Ministry of Environment.
Range Act	Provisions regarding the use of Crown range for grazing, hay production or other purposes, including provisions regarding the control of livestock, revegetation, etc., in grazing reserves.	Ministry of Forests.
Soil Conservation Act	Approval and permit necessary for the removal of soil from an agricultural land reserve. Regulations to prevent and control soil erosion.	District Agriculturist, Ministry of Agriculture & Food.
Utilities Commission Act	Energy project and energy operation certificate for the construction and operation of a regulated project. Energy removal certificate for the removal of an energy resource from the province. Regulation of public utilities, including certificates of public convenience and necessity from Utilities Commission regulation of petroleum industry.	Energy Resources Division, Ministry of Energy, Mines & Petroleum Resources.

STATUTE	APPROVALS	AGENCY
Water Act	Water licence or approval from the Comptroller of Water Rights for the use, diversion or storage of water for the alteration of streams or channels and operation of works in and about water bodies. Permits authorizing the flooding of Crown land or the construction, maintainance or operation of works on Crown land.	Water Management Branch, Ministry of Environment
Weed Control Act	Requirements regarding the control and eradication of noxious weeds growing or located on land and premises.	District Agriculturist, Ministry of Agriculture & Food.
Wildlife Act, Firearm Act	Hunting, trapping and guiding licences; Restrictions and regulations regarding hunting, trapping, guiding and the preservation of wildlife habitat; Permits for shooting; Control of firearms.	Fish & Wildlife Branch, Ministry of Environment.

Appendix 4: Bibliography

Environment and Land Use Committee, *Guidelines for Benefit-Cost Analysis*, 1978.

Ibid., *Guidelines for Coal Development*, 1976.

Ibid., *Guidelines for Linear Development*, 1977.

Environment and Land Use Committee Secretariat, *Environmental and Social Impact Compensation/Mitigation Guidelines*, 1980.

Ibid., *(Draft) Guidelines for Major Developments*, 1980.

Ministry of Agriculture, *Guidelines for Linear Development on Agricultural Land* (no date).

Ministry of Energy, Mines and Petroleum Resources, *An Energy Secure British Columbia*, 1980.

Ibid., *Guidelines for Construction and Cleanup of Roads, Leases and Seismic Lines in Petroleum Exploration Areas*, March, 1980.

Ibid., *Procedures for Obtaining Approval of Metal Mine Development*, 1981.

Ibid., *Implementation of Terms and Conditions of an Energy Project Certificate and Energy Operation Certificate*, Technical Discussion Paper, 1982.

Ministry of Environment, *Pollution Control Objectives for the Chemical and Petroleum Industries of British Columbia*, 1980.

Ibid., *Pollution Control Objectives for the Forest Products Industry of British Columbia*, 1977.

Ibid., *Pollution Control Objectives for the Mining, Smelting and Related Industries of British Columbia*, 1979.

Ministry of Industry and Small Business Development, *A Procurement Policy for Major Project Developments*, 1981.

APPENDIX D

DEMAND SCENARIOS FOR B.C. HYDRO

YUKON RIVER BASIN COMMITTEE

APPENDIX D

BRITISH COLUMBIA
J.O'RIORDAN

CANADA
E.M. CLARK (Chairman)
D.M. WATSON

YUKON
M.C. McKAY

1982 06 14

MEMO TO B. Brickman

FROM T. Hodge

SUBJECT DEMAND SCENARIOS FOR B.C. HYDRO

The following three cases would provide an appropriate framework for the Electric Transmission Interconnection Study proposed by B.C. Hydro.

CASE I: An additional 60 MW capacity required to provide an average of 280 gigawatt hours per annum.

CASE II: An additional 200 MW capacity required to provide an average of 1050 gigawatt hours per annum.

CASE III: An additional 400 MW capacity required to provide an average of 2100 gigawatt hours per annum.

The above cases as well as the existing situation are plotted on the attached figure which shows annual electrical energy use vs. average plant requirement calculated by assuming a 60% load factor. The estimates are crude and I have made no attempt to justify "Peak Demands". However, I think the figures are adequate for present needs.

All three cases lie above the Hildebrandt-Young projections to 2000 as well as the Soft Energy Path Study projections to 2025. However, to obtain the spread in cost figures from B.C. Hydro, something significantly different from the existing situation is required. In the following paragraphs, the three cases are compared to existing forecasts.

CASE I Slightly above the Hildebrandt-Young high case (high population and mining estimates). Roughly equivalent to Foster Research's (1979) Base Case which assumes major increases in Mac Pass mining activity after 1993, causing a 50% increase in industrial energy use and a rise of approximately 20% in the commercial and residential energy uses by 1998.

CASE II Equivalent to Sigma Resources Consultants Ltd. (1975) Case 2E - high population growth, high mining growth and a 100 MW smelter load.

MR. W.G. WHITLEY, DIRECTOR, YUKON RIVER BASIN STUDY
ROOM 220, 204 RANGE ROAD, WHITEHORSE, YUKON, Y1A 3V1, TEL. 403-668-3006

CASE III — Roughly equivalent to Foster Research (1979) High Case which includes:

a. New mines at Minto (copper) and Watson Lake (barite)

b. Lead zinc smelter

c. Partial electrification of the Foothills Alaska Highway Natural Gas Pipeline as well as the Dempster Lateral

d. Exports to Canada Tungsten, NWT

e. Exports to Cassiar, B.C.

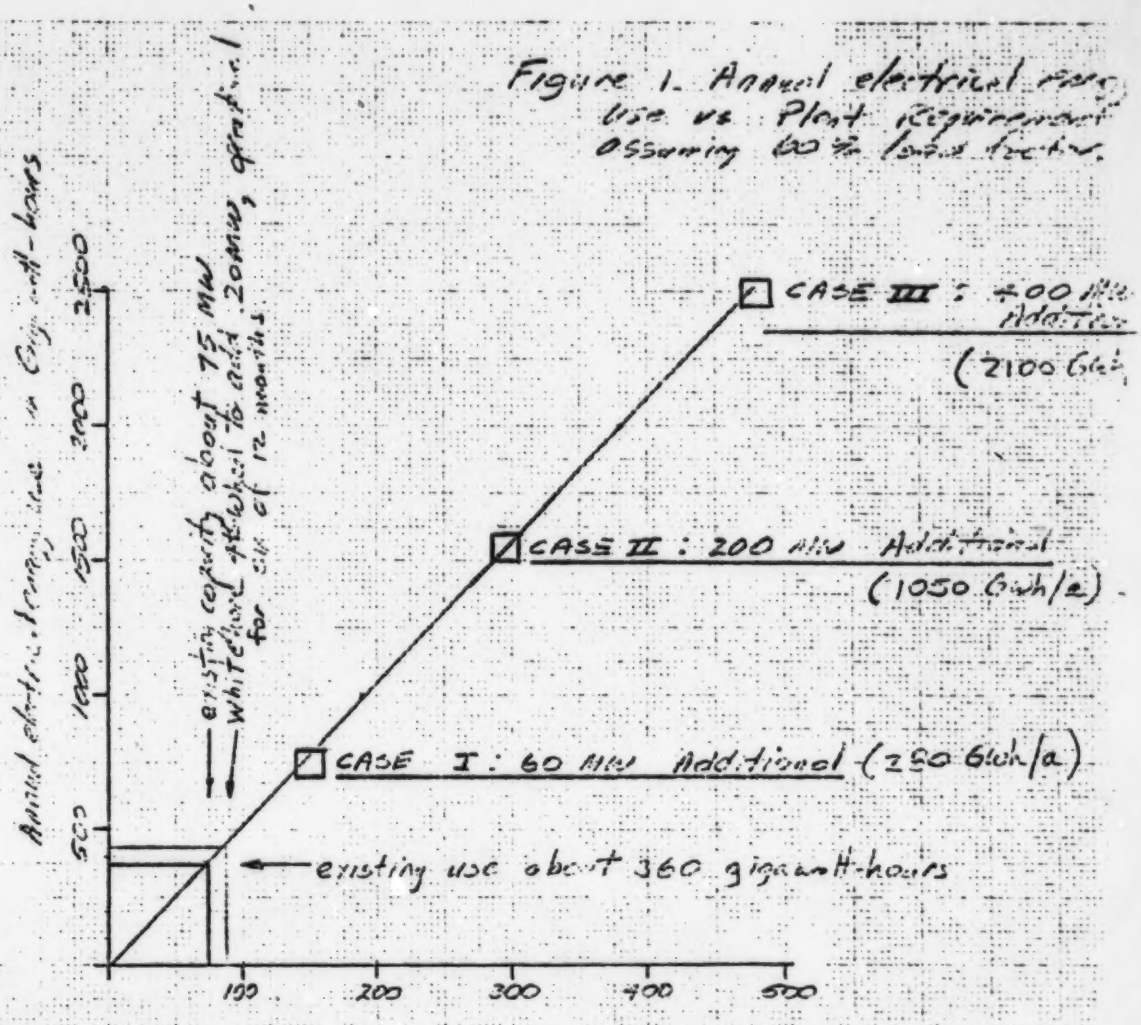
f. Exports to Skagway, Alaska

Information Required from B.C. Hydro

Ultimately the Work Group will have to attempt to establish the economic cut off point for an interconnection with B.C. To assist, B.C. Hydro should be asked to develop a plot of estimated cost/KWh to the Yukon utility vs. total annual Yukon energy consumption bought through the tie line. The calculations and assumptions for such a plot should be carefully outlined.

T. Hodge
Enclosure
TH/lj

Figure 1. Annual electrical energy use vs Plant requirement assuming 60% load factor.



NCPC SITE INVESTIGATIONS 81/82

1. Granite Canyon (Pelly R.)	100 - 350 MW
2. Mid Yukon (Yukon R.)	75 - 600 MW
3. False Canyon (Frances R.)	60 MW
4. Hootalinqua (Pelly R.)	38 MW
5. Ross Canyon (Ross R.)	34 MW

MAPS NOT

FILMED

CARTES

OMISES